DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL CONSTRUCTION PERMIT

Permit No.: AQ0215CPT02 Date: **Final – January 31, 2007**

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Construction Permit No. AQ0215CPT02 to the Permittee listed below.

Permittee:	**City of Unalaska, Department of Public Utilities** P.O. Box 610 Unalaska, AK 99685
Owner/Operator:	Same as Permittee
Stationary Source:	**Dutch Harbor Power Plant**
Location:	UTM Coordinates Zone 3, Northing 5972.60 km, Easting 399.06 km
Physical Address:	1732 East Point Road, Dutch Harbor, AK 99685
Permit Contact:	Chris Hladick, (907) 581-1260
Project:	Power Plant Renovation, phase 1 and 2

The Dutch Harbor Power Plant (DHPP) is classified as a PSD major stationary source. Both phases of this project are classified under **18 AAC 50.306** as significant modifications to the DHPP for NO_X. Both phases require a minor permit under **18 AAC 50.502(c)(2)(B)** because they contain an emission unit with a rated capacity of 10 mmBtu/hr or more in an SO_2 special protection area. Phase 1 also requires a minor permit under **18 AAC 50.502(c)(3)** for PM-10 because the project causes an increase in over 10 tpy of PM-10. The permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50.

This permit authorizes the Permittee to operate under the terms and conditions of this permit, and as described in the original permit application and subsequent application supplements listed in Section 3, except as specified in this permit.

The Permittee shall **not operate** the emission units authorized in this permit until after the Department issues a revised operating permit that includes the provision of this construction permit. The Permittee **may begin actual construction** of the emission units authorized in this permit upon permit issuance.

John F. Kuterbach
Manager, Air Permits Program

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Abbreviations/Acronyms

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
AS	Alaska Statutes
ASTM	American Society of Testing and Materials
C.F.R.	Code of Federal Regulations
DHPP	Dutch Harbor Power Plant
EPA	Environmental Protection Agency
FITR	Fuel Injection Timing Retard
MR&R	Monitoring, Recordkeeping, and Reporting
N/A	Not Applicable
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RM	Reference Method
rpm	revolutions per minute
SIC	Standard Industrial Classification
SN	Serial Number
TAR	Technical Analysis Report
TBD	To Be Determined

Units and Measures

bhp	brake horsepower or boiler horsepower
gr./dscf	grains per dry standard cubic feet (1 pound = 7,000 grains)
dscf	dry standard cubic foot
gph	gallons per hour
GW	GigaWatt (electric) (= 10^6 kW)
kW	kilowatts (electric)
lbs	pounds
mmBtu	million British thermal units
MW	MegaWatt (electric)
ppm	parts per million
ppmv	parts per million by volume
tph	tons per hour
tpy	tons per year
wt%	weight percent

Pollutants

CO	Carbon Monoxide
HAPS	Hazardous Air Pollutants
NO_X	Oxides of Nitrogen
NO_2	Nitrogen Dioxide
NO	Nitric Oxide
PM-10	Particulate Matter with an aerodynamic diameter less than 10 microns
S	Sulfur
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compound

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Section 1 Emission Unit Inventory

1. **Authorization.** The Permittee is authorized to install and operate the existing and new emission units listed in Table 1 at the Dutch Harbor Power Plant (DHPP) subject to terms and conditions of this permit. This permit becomes invalid if initial construction (phase 1) is not commenced within 18 months after issuance, or if construction is discontinued for a period of 18 months or more, or if construction is not completed in a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

Table 1 – Emission Unit Inventory[a]

Unit No.	Existing or new?	Description	Rating/Size	Installation (Mo/Yr)
1	Existing (Generator #1)	Caterpillar D-353E	300 kW	10/85
2	Existing (Generator #2)	Caterpillar D-353E	300 kW	3/87
3	Existing (Generator #3)	Caterpillar D-398	600 kW	10/86
4	Existing (Generator #4)	Caterpillar 3512	830 kW	10/86
5	Existing (Generator #5)	Caterpillar 3512	620 kW	10/85
6	Existing (Generator #6)	Caterpillar 3516	1,440 kW	10/85
7	Existing (Generator #8)	Caterpillar 3516	1,180 kW	11/89
8	Existing (Generator #9)	Caterpillar 3512B	1,230 kW	1/94
9	Existing	Tank #1 (diesel fuel storage)	10,000 gal	1943
10	Existing	Tank #2 (diesel fuel storage)	10,000 gal	1943
11	Existing	Tank #3 (diesel fuel day tank)	10,000 gal	1995
13	New	Wärtsilä 12V32C Generator (720 rpm)	5,211 kW	Est. 2007
14	New	Wärtsilä 12V32C Generator (720 rpm)	5,211 kW	Est. 2007
15	New	Post 2007 Model Year Generator[c]	5,000 kW	TBD
16	New	Post 2007 Model Year Generator[c]	5,000 kW	TBD
17	New	Caterpillar C-9 DITA, DM8501 Black Start Engine (1,800 rpm)	250 kW	Est. 2007
18	New	Diesel Fuel Storage Tank	10,000 gal	Est. 2007

[a] The listed emission units have specific monitoring, recordkeeping, or reporting conditions in this construction permit. The description and rating are for identification purposes only.

[b] In this table "TBD" means "to be determined", "rpm" means "revolutions per minute", and "Est" means "estimated".

[c] Permit conditions presume engines with displacement greater than 30 liters per cylinder.

2. **Unit Information.** For each new unit listed in Table 1, submit to the Department the installation date,[1] serial number, specification sheet,[2] and the electronic fuel control

[1] The installation date is the same as the initial start-up date, i.e. the first day that the unit is operated, whether for testing or for normal operations.

[2] The specification sheet is a one to ten page summary of the unit, including applicable emissions specifications, if available.

settings, of the unit within 90 days after initial startup of the unit. For Units 15 and 16, include the make, model, rpm, power output, and cylinder displacement.

3. **Labeling Requirements.** The Permittee shall label each new emission unit listed in Table 1 with the emission unit number, in a conspicuous location on or adjacent to the unit, within 90 days of unit initial startup.

4. **Nomenclature.** For purposes of this permit,

    a. Units 1 through 6 are known as "Emergency Backup Units," and

    b. during phase 1, Units 8, 9, 13, 14 and 17 are known as "Phase 1 Primary Units."

5. **Stack Requirements.** For Units 13, 14, 15, 16 and 17 construct stacks with:

    a. sampling ports that comport with 40 CFR 60, Appendix A, Method 1, Section 2.1, and stack or duct *free of cyclonic flow* at the port location during the applicable test methods and procedures;

    b. safe access to sampling ports; and

    c. utilities for emission sampling and testing equipment.

Section 2 Assessable Emissions

6. **Assessable Emissions.**

6.1 The Permittee shall pay to the Department an annual emission fee based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year. The quantity for which fees will be assessed is the lesser of:

a. the source's assessable potential to emit of

(i) 1,742 tpy during phase 1;[3] and

(ii) 1,357 tpy during phase 2;[4] or

b. the source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the Department, when demonstrated by:

(i) an enforceable test method described in 18 AAC 50.220;

(ii) material balance calculations;

(iii) emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

(iv) other methods and calculations approved by the Department.

7. **Assessable Emission Estimates.** Emission fees will be assessed as follows:

7.1 no later than March 31 of each year, the Permittee may submit an estimate of the source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Juneau, AK 99801-1795; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or

7.2 if no estimate is received on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set forth in condition 6.1a.

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[3] Phase 1 starts upon initial startup of Units 13, 14, 17, or 18.
[4] Phase 2 starts upon initial startup of Units 15 or 16.

Section 3 Emission Unit-Specific Requirements

State Emission Standards for the Diesel Engines

8. **Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from Emission Units 13 through 17 listed in Table 1 to reduce visibility through the exhaust effluent by any of the following:

   a. more than 20 percent for a total of more than three minutes in any one hour;[5]

   b. more than 20 percent averaged over any six consecutive minutes.[6]

   8.1 Conduct an initial visible emission surveillance for Emission Units 13 through 17 within 30 days after each units installation, following 40 C.F.R. 60, Appendix A-4, Method 9, adopted by reference in 18 AAC 50.040(a). Conduct observations for 18 minutes to obtain 72 consecutive 15-second opacity observations, and use the Visible Emissions Field Data Sheet and Visible Emissions Observation Record included in Attachment 1.

   8.2 Include copies of the observation results in the next operating report under condition 49.

9. **Particulate Matter (PM).** The Permittee shall not cause or allow PM emitted from Emission Units 13 through 17 listed in Table 1 to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

10. **Sulfur Compound Emissions.** The Permittee shall not allow sulfur emissions, expressed as SO_2, from Emission Units 13 through 17 to exceed 500 parts per million (ppm) over three hours.

Owner Requested Limits for PSD Avoidance

11. **Phase 1 Operational Limits to avoid PSD for SO_2, PM-10, and CO.** Phase 1 starts upon initial startup of Unit 13, 14, or 17; and ends upon start of phase 2. During phase 1 of the project, the Permittee shall:

    a. limit operation of Units 7 and 8 to no more than 3,000 hours per year, each;

    b. limit operation of Unit 17 to no more than 500 hour per year; and

    c. not operate Unit 15 or Unit 16.

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[5] For purposes of this permit, the "more than three minutes in any one hour" criterion in this condition will no longer be effective when the Air Quality Control (18 AAC 50) regulation package effective 5/3/02 is adopted by the U.S. EPA.

[6] The six-minute average standard is enforceable only by the State until 18 AAC 50.055(a)(1) and 50.050(a), dated May 3, 2002, is approved by EPA into the SIP at which time this standard becomes federally enforceable.

11.1 Before initial startup of Emission Units 13 or 14, install a continuous system for recording and monitoring the operating hours for each Emission Unit 7, 8, and 17. Maintain and operate these systems in good working order.

11.2 By the 15th of each month, calculate the operating hours for previous 12 months for each unit listed in condition 11.1. If the total for any unit exceeds a limit in this condition, report as excess emissions under condition 48.

11.3 Include totals calculated under condition 11.2 in the report required by condition 49.

12. **Phase 1 Fuel Sulfur Content to avoid PSD for SO_2.** During phase 1, the Permitteee shall limit fuel sulfur in all fuel burning equipment to 0.10 wt%S. Monitor, record, and report as follows:

12.1 Obtain a statement or reciept from the fuel supplier certifying the maximum sulfur content of the fuel for each shipment of fuel delivered to DHPP. If a certified statement or reciept is not available from the supplier, analyze a representative sample of any fuel added to any tank in accordance with condition 12.2.

12.2 If required under this permit to determine the sulfur content of fuel oil, use ASTM method D129-00, D1266-98, D1552-95, D2622-98, D4294-98, D4505-99, or an alternative method approved in writing by the Department.

12.3 Prior to start of phase 1, measure and record the initial fuel sulfur content of each fuel storage tank, in accordance with condition 12.2.

12.4 Except as indicated in condition 12.5, calculate and record the sulfur content, by weight, of the fuel in each tank, after each time fuel is added to a tank, using Equation 1.

Equation 1

$$S_T = \frac{(Q_D \times S_D) + (Q_{BD} \times S_{BD})}{Q_T}$$

Where:

Where:	Q_D	=	Quantity of Delivered Fuel, pounds
	S_D	=	Sulfur content of Delivered Fuel, percent sulfur by weight
	Q_{BD}	=	Quantity of Fuel in Tank before Delivery, pounds
	S_{BD}	=	Sulfur content of Fuel in Tank before Delivery, percent sulfur by weight
	S_T	=	Sulfur content of blended fuel in the tank, percent sulfur by weight (will be S_{BD} for next calculation)
	Q_T	=	Total Quantity of Fuel in Tank ($Q_D + Q_{BD}$), pounds

12.5 If the fuel sulfur content in a given tank (S_{BD}) is less than 0.10 wt%S and the sulfur content of a given fuel oil delivery is less than 0.10 wt%S, then the Permittee may forego fuel sulfur content calculations in condition 12.4 for that delivery. If the Permittee foregoes fuel sulfur content calculations for a delivery, then for the next fuel delivery for which the fuel sulfur content is greater than 0.10 wt%S, the Permittee shall either

a. assume the fuel sulfur content of the fuel in the tank is 0.10 wt%S; or

b. test the fuel sulfur content of the fuel in the tank in accordance with condition 12.2.

12.6 Keep records of statements or receipts from the fuel supplier showing sulfur content and quantity of each shipment of fuel under condition 12.1, results of each sulfur measurement required under condition 12.2, and each fuel sulfur calculation conducted under condition 12.4.

12.7 During phase 1, if the fuel sulfur content combusted in any fuel burning emission unit exceeds 0.10 wt%S, report as excess emissions under condition 48.

12.8 Include the records required under condition 12.6 in the report required by condition 49.

13. **Phase 2 Operational Limits to avoid PSD for SO_2, PM-10, CO, and VOC.** Phase 2 starts upon initial startup of either Unit 15 or Unit 16 (whichever comes first). Immediately upon start of phase 2, the Permitte shall:

a. decommission (remove) Units 1 through 8;

b. limit power generation of Units 13 and 14 to no more than to 73.04 GigaWatt-hours per year (GW-hrs/yr), combined;

c. limit power generation of Units 15 and 16 to no more than to 36.52 GW-hrs/yr, combined; and

d. limit operation of Unit 17 to no more than 500 hour per year.

13.1 Before initial startup of Unit 15 or 16, install a continuous system for recording and monitoring the GW-hrs for each Emission Unit 13, 14, 15, and 16. Maintain and operate these systems and the operating hour system for Unit 17 in good working order.

13.2 By the 15th of each month, calculate the GW-hrs or operating hours (as applicable) for the previous 12 months for each unit listed in condition 13.1. If the total for any unit exceeds a limit in this condition, report as excess emissions under condition 48.

13.3 Include the totals calculated under condition 13.2 in the report required by condition 49.

14. **Phase 2 Fuel Sulfur Content to avoid PSD for SO_2.** During phase 2, the Permitteee shall limit fuel sulfur content of fuel combusted in

    a. Units 13, 14, and 17 to no greater than 0.10 wt%S; and

    b. Units 15 and 16 to no greater than 0.0015 wt%S.

    14.1 Monitor, record and report fuel sulfur content of each tank as indicated in condition 12, except condition 12.7.

    14.2 During phase 2, report as excess emissions under condition 48

    a. if fuel sulfur content of fuel combusted in Units 13, 14, or 17, exceeds 0.10 wt%S; or

    b. if the fuel sulfur content of fuel combusted in Units 15 or 16 exceed 0.0015 wt%S.

15. **Phase 1 PSD Avoidance for CO.** The Permittee shall limit CO emissions during phase 1 to less than 178 tpy[7] from Units 13 and 14, combined.

    15.1 Starting 14 days after each unit initial start-up, monitor engine load (in kW) for each hour Units 13 and 14 operate.

    15.2 Calculate average hourly load for each hour each unit operates.

    15.3 Except as indicated in condition 15.7, keep daily and monthly records of the number of hours that each unit operates at an average hourly load

    a. greater than or equal to 75 percent of maximum load;[8]

    b. greater than or equal to 50 and less than 75 percent of maximum load; and

    c. less than 50 percent of maximum load.

    15.4 By the 5th day of each month, calculate the three-month running total and the 12-month running total hours for each unit at each load range described in condition 15.3.

    15.5 Except as indicated in condition 15.7, the **first** time the total hours for any Unit 13 and 14 operating at less than 75 percent of maximum load exceeds 758 hours per unit per three month period,

    a. conduct a set of three CO source test at 50 percent load (plus or minus five percent) and a set of three source tests at 25 percent load;

    b. conduct the set of tests on one of Emission Units 13 or 14;

[7] In this condition tpy means tons per 12 consecutive months. The monitoring, recordkeeping, and reporting in condition reflect the Departments intention that this limit is on a 12 consecutive month basis.

[8] For Units 13 and 14, maximum load is 5,211 kW (as noted in "Abbreviations/Acronyms", kW means kilowatt-electric.

c. use procedures set out in Section 5, and conduct the test within 60 operating days after the last day of the month that exceeded the 758 hours per unit per three month period; and

d. calculate 12 month rolling total CO emissions as indicated in condition 15.6.

15.6 If required under condition 15.5, calculate 12 month rolling total CO emissions for Units 13 and 14 combined as follows:

Equation 2 $$CO = \left[\left(11.3 \times H_{\rangle 75}\right) + \left(ST_{50} \times H_{\langle 75\&>50}\right) + \left(ST_{25} \times H_{\langle 50}\right)\right]\left(\frac{1\,ton}{2000\,lb}\right)$$

Where:
- CO = CO emissions in tons per 12 months;
- $H_{>75}$ = number of hours operated at greater than or equal to 75 percent of maximum load;
- $H_{<75\&>50}$ = number of hours operated at less than 75 and greater than or equal to 50 percent of maximum load; and
- ST_{50} = Department approved source test emission factor at 50 percent of maximum load **or** guaranteed manufacturer emission factor in lb/hr for 50 percent of maximum load.
- $H_{<50}$ = number of hours operated at less than 50 percent of maximum load; and
- ST_{25} = Department approved source test emission factor at 25 percent of maximum load **or** guaranteed manufacturer emission factor in lb/hr for 25 percent of maximum load.

15.7 The Permittee may obtain guaranteed manufacturer's CO emission factors for 50 percent and 25 percent of maximum load for Units 13 and 14. If guaranteed emission factors at both 50 and 25 percent load are less than or equal to 11.3 lb CO/hr, the Permittee is not required to track load under condition 15.3, and is not required to calculate emissions under condition 15.6.

15.8 If Department-approved source tests conducted under condition 15.5 indicate that CO emission factors at both 50 percent and 25 percent of maximum load are less than or equal to 11.3 lb CO per hour, the Permittee is not required to track load under condition 15.3, and is not required to calculate emissions under condition 15.6.

15.9 If 12 month rolling total CO emissions exceed the limit in this condition, report as excess emissions under conditon 48.

16. **Phase 2 PSD Avoidance for CO.** The Permittee shall limit CO emissions during phase 2 to less than 213 tpy[9] from Units 13 through 16, combined.

16.1 Monitor engine load (in kW) for each hour Units 13 and 14 operate.

[9] In this condition tpy means tons per 12 consecutive months. The monitoring, recordkeeping, and reporting in condition reflect the Departments intention that this limit is on a 12 consecutive month basis.

16.2 Starting 14 days after each unit initial start-up, monitor engine load (in kW) for each hour Units 15 and 16 operate.

16.3 Calculate average hourly load for each hour each unit operates.

16.4 Except as indicated in condition 16.9, keep daily and monthly records of the total number of hours that each unit operates at an average hourly load

a. greater than or equal to 75 percent of maximum load;[10]

b. greater than or equal to 50 and less than 75 percent of maximum load; and

c. less than 50 percent of maximum load.

16.5 If the Permittee has already conducted a source test under condition 15.4, comply with condition 16.5a, otherwise comply with condition 16.5b.

a. Calculate 12-month rolling total CO emissions as indicated in condition 16.7.

b. The **first** time the combined operating hours for Units 13 and 14 operating at less than 75 percent of maximum load exceed **1,230** hours per three month period,

(i) conduct a set of three CO source test on either Unit 13 or 14 at 50 percent of maximum load (plus or minus five percent) and a set of three source tests at 25 percent load;

(ii) use procedures set out in Section 5, and conduct the test within 60 operating days after exceeding the **1,230** hours per three month period;

(iii) calculate CO emissions as indicated in condition 16.7.

16.6 If Units 15 and 16 are identical make, model, and engine configuration, comply with condition 16.6a, otherwise comply with condition 16.6b.

a. Except as indicated in conditions 16.8 and 16.9, the **first** time the combined operating hours for Units 15 and 16 operating at less than 75 percent of maximum load exceed **641** hours per three month period,

(i) conduct a set of three CO source test on either Unit 15 or 16 at 50 percent of maximum load (plus or minus five percent) and a set of three source tests at 25 percent load;

(ii) use procedures set out in Section 5, and conduct the tests within 30 operating days after exceeding the **641** hours per three month period; and

(iii) calculate 12 month rolling total CO emissions as indicated in condition 16.7.

b. Except as indicated in conditions 16.8 and 16.9, the **first** time the combined operating hours for Units 15 and 16 operating at less than 75 percent of maximum load exceed **641** hours per three month period,

[10] For Units 15 and 16, "maximum load" is 100 percent load as listed on vendor specification sheets.

(i) conduct a set of three CO source test on each Unit 15 and 16 at 50 percent of maximum load (plus or minus five percent) and a set of three source tests at 25 percent load

(ii) use procedures set out in Section 5, and conduct the tests within 60 operating days after exceeding the **641** hours per three month period; and

(iii) calculate CO emissions as indicated in condition 16.7.

16.7 If required under condition 16.5 or condition 16.6, calculate 12 month rolling total CO emissions for Units 13, 14, 15, and 16, combined, as follows:

Equation 3 $$CO = \left[\left(11.3 \times H_{\rangle 75}\right) + \left(ST_{50} \times H_{\langle 75\&>50}\right) + \left(ST_{25} \times H_{<50}\right)\right]\left(\frac{1\,ton}{2000\,lb}\right)$$

Where:

CO	=	CO emissions in tons per 12months;
$H_{>75}$	=	number of hours operated at greater than or equal to 75 percent of maximum load;
$H_{<75\&>50}$	=	number of hours operated at less than 75 and greater than or equal to 50 percent of maximum load;
ST_{50}	=	Department approved source test emission factor at 50 percent of maximum load **or** guaranteed manufacturer emission factor in lb/hr for 50 percent of maximum load. If there is no Department approved source test emission factor or guaranteed emission factor for either the phase 1 engines or phase 2 engines, use a CO emissions factor of 0.85 lb/mmBtu and assume 130,500 mmBtu/gal, and vendor supplied maximum fuel consumption rate in gal/hr.
$H_{<50}$	=	number of hours operated at less than 50 percent of maximum load; and
ST_{25}	=	Department approved source test emission factor at 25 percent of maximum load **or** guaranteed manufacturer emission factor in lb/hr for 25 percent of maximum load. If there is no Department approved source test emission factor or guaranteed emission factor for either the phase 1 engines or phase 2 engines, use a CO emissions factor of 0.85 lb/mmBtu and assume 130,500 mmBtu/gal, and vendor supplied maximum fuel consumption rate in gal/hr.

16.8 If Units 15 and 16 are Wärtsilä 12V32C generators, the Permittee may use approved source test results from Units 13 or 14, if a test was conducted under condition 15.4.

16.9 The Permittee may obtain guaranteed manufacturer's CO emission factors for 50 percent and 25 percent of maximum load for Units 13, 14, 15, and 16. If guaranteed emission factors at both 50 and 25 percent load for all engines are less than or equal to 11.3 lb CO/hr, the Permittee is not required to track load under condition 16.4, and is not required to calculate emissions under condition 16.7.

16.10 If Department-approved source test conducted under **either** condition 15.5 or16.5, **and** 16.6 indicate that CO emission factors at 50 percent and 25 percent of maximum load are less than or equal to 11.3 lb CO per hour, the Permittee is not required to track load under condition 16.4 and is not is not required to calculate emissions under condition 16.7.

16.11 If 12 month rolling total CO emissions exceed a limit in this condition, report as excess emissions under conditon 48.

Best Available Control Technology

17. **NO_X BACT Limit for Units 13 and 14.** Limit the NO_X emission rate, expressed as NO_2 averaged over three hours, from each Emission Unit 13 and 14 to no greater than **13.6 g/kWh** at all times. Monitor, record, and report as follows:

17.1 Operate each unit with FITR and with an aftercooler with a separate low temperature cooling water circuit.

17.2 In addition to information required by condition 2, provide to the Department within 90 days of initial startup of each Emission Unit 13 and 14 the camshaft timing and engine FITR settings.

17.3 No later than 90 days after initial startup of the first of Emission Units 13 or 14, and after every engine re-configuration, conduct NO_X source tests to ascertain compliance with the NO_X emission rate limit in this condition. (For the initial source test, conduct the test on one of Emission Units 13 or 14, for engines reconfigurations, conduct the test on the reconfigured engine.) Conduct the test at 100 percent load. Determine the emission rate in g/kWh expressed as NO_2, using exhaust properties determined by Reference Method 19 and exhaust gas measurements as set out in Section 5.

17.4 If any NO_X source test results in a NO_X emission rate greater than the limit in this condition, report as excess emissions under condition 48.

18. **NO_X BACT Limit for Units 15 and 16.** Limit the NO_X emission rate, expressed as NO_2 averaged over three hours, from each Emission Unit 15 and 16 to no greater than **1.36 g/kWh** at all times. Monitor, record, and report as follows:

18.1 Operate each unit with FITR and with an aftercooler with a separate low temperature cooling water circuit.

18.2 In addition to information required by condition 2, provide to the Department within 90 days of initial startup of each Emission Unit 15 and 16 the camshaft timing and engine FITR settings.

18.3 If Units 15 and 16 are identical make, model, and engine congifuration, comply with condition 18.3a, otherwise comply with condition 18.3b.

a. No later than 90 days after initial startup of the first of Emission Units 15 or 16, and after every engine re-configuration, conduct NO_X source tests to ascertain compliance with the NO_X emission rate limit in this condition. (For the initial source test, conduct the test on one of Emission Units 15 or 16, for engines reconfigurations, conduct the test on the reconfigured engine.)

Conduct the test at 100 percent load. Determine the emission rate in g/kWh expressed as NO_2, using exhaust properties determined by Reference Method 19 and exhaust gas measurements as set out in Section 5.

b. No later than 90 days after initial startup of each Emission Unit 15 and 16, and after every engine re-configuration, conduct NO_X source tests to ascertain compliance with the NO_X emission rate limit in this condition. Conduct the test at 100 percent load. Determine the emission rate in g/kWh expressed as NO_2, using exhaust properties determined by Reference Method 19 and exhaust gas measurements as set out in Section 5.

18.4 Keep a log of engine every engine re-configuration or tune up. Include a copy of the log with the operating report required by condition 49.

18.5 If any NO_X source test results in a NO_X emission rate greater than the limit in this condition, report as excess emissions under condition 48.

18.6 **NO_X BACT Limit for Unit 17.** Limit the NO_X emission rate, expressed as NO_2 averaged over three hours, from Emission Unit 17 to no greater than **5.75 g/kWh** at all times.

19. The Permittee shall reassess NO_X BACT for phase 2 if phase 2 starts more than 18 months after permit issuance.

Ambient Air Quality Protection Requirements for NO_X, CO, PM-10 and SO_2

20. **Stack Configuration.**

20.1 For Units 13, 14, 15, 16, and 17, construct and maintain each exhaust stack:

a. with uncapped, vertical outlets – flapper valves, or similar, are allowed for these units as long as they do not hinder the vertical momentum of the exhaust plume; and

b. to have a release point no less than 26 meters above ground.

20.2 Provide as-built drawings of each exhaust stack subject to condition 20.1 in the first operating report submitted after initial startup of the given unit. Include photographs showing each stack relative to the DHPP building and surrounding terrain.

21. During phase 1, the Permittee shall

a. comply with operating restrictions listed in condition 11;

b. comply with fuel sulfur requirements listed in condition 12; and

c. not operate an Emergency Backup Unit(s), unless a phase 1 Primary Unit(s) of equal or greater capacity is not concurrently operating.

21.1 Monitor compliance with condition 21.c by recording:

a. the start and stop day/time of the Emergency Backup Unit,

b. the rated capacity of the Emergency Backup Unit(s);

c. the stop and start day/time of the off-line Phase 1 Primary Unit(s); and

d. the rated capacity of the off-line Phase 1 Primary Unit(s).

21.2 Report as excess emissions under condition 48 if:

a. the start day/time of the Emergency Backup Unit occurs prior to the stop day/time of the off-line Phase 1 Primary Unit(s);

b. the stop day/time of the Emergency Backup Unit occurs after the start day/time of the off-line Phase 1 Primary Unit(s); and/or

c. the total rated capacity of the Emergency Backup Unit(s) exceeds the total rated capacity of the off-line Phase 1 Primary Unit(s).

22. After start of phase 2, the Permittee shall

a. comply with the operating restrictions in condition 13

b. comply with the fuel sulfur requirements listed in condition 14; and

c. comply with the NO_X emission limit in condition 18.

New Source Performance Standards, Subpart IIII[11]

23. The provisions of [conditions 24 through 36] are applicable to [Permittees that own and operate] stationary compression ignition (CI) internal combustion engines (ICE) as specified in [conditions 23.1 and 23.2]. For the purposes of [conditions 24 through 36], the date that construction commences is the date the engine is ordered by the [Permittee], as described in 40 C.F.R. 60.4200(a).

23.1 [Permittees that own or operate a] stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are manufactured after April 1, 2006 and are not fire pump engines as described in 40 C.F.R. 60.4200(a)(2)(i); or

23.2 [Permittees that own or operate] stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005, as described in 40 C.F.R. 60.4200(a)(3).

24. [The Permittee that owns and operates a non-emergency stationary CI ICE with a displacement of greater than or equal to to 30 liters per cylinder] must meet the requirements in [conditions 24.1 and 24.2] as described in 40 C.F.R. 60.4204(c).

24.1 Reduce NO_X emissions by 90 percent or more, or limit the emissions of NO_X in the stationary CI ICE to 1.6 g/kW-hr as described in 40 C.F.R. 60.4204(c)(1).

24.2 Reduce PM emission by 60 percent or more, or limit the emissions of PM in the stationary CI ICE to 0.15 g/kW-hr as described in 40 C.F.R. 60.4204(c)(2).

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[11] For all "New Source Performance Standard" conditions, [brackets] indicate NSPS language as revised by Department to fit Department permit language. Otherwise, NSPS language is verbatim from Federal Register/Vol. 71, No. 132, dated July 11, 2006, with the exception of punctuation and abbreviations.

25. [The Permittee] must operate and maintain stationary CI ICE that achieve the emission standards as required in [condition 23] according to the manufacturer's written instructions or procedures developed by [the Permittee] that are developed by the engine manufacturer, over the entire life of the engine, as described in 40 C.F.R. 60.4206.

26. Beginning October 1, 2007, [the Permittee that owns and operates a] stationary CI ICE subject to [Subpart IIII] that use diesel fuel must use diesel fuel that meets the requirements of 40 C.F.R. 80.510(a) as described in 40 C.F.R. 60.4207(a).

27. [The Permittee that owns and operates a] pre-2011 model year stationary CI ICE subject to [conditions 24 through 36] may petition the Administrator[12] for approval to use remaining non-compliant fuel that does not meet the fuel requirements of [condition 26] beyond the dates required for the for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, [the Permittee] is required to submit a new petition to the Administrator, as described in 40 C.F.R. 60.4207(c).

28. [The Permittee that owns and operates a] pre-2011 model year stationary CI ICE subject to [conditions 24 through 36] that are located in areas of Alaska not accessible by the Federal Aid Highway system may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of [condition 26]. [The Permittee] must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, [the Permittee] is required to submit a new petition to the Administrator, as described in 40 C.F.R. 60.4207(d).

29. After December 31, 2008, [the Permittee] may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines, as described in 40 C.F.R. 60.4208(a).

30. [A Permittee that owns or operates a] stationary CI ICE equipped with a diesel particulate filter to comply with the emission standards in [condition 24.2], the diesel particulate filter must be installed with a backpressure monitor that notifies [the Permittee] when the high backpresssure limit of the engine is approached, as described in 40 C.F.R. 60.4209(b).

31. If [a Permittee is an owner or operator and must comply with the emission standards specified in conditions 24 through 36, the Permittee] must operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions or procedures developed by [the Permittee] that are approved by the engine manufacturer. In addition, [the Permittee] may only change those settings that are permitted by the manufacturer. [The Permittee] must also meet the requirements of 40 C.F.R. part 89, 94, and/or 1068, as they apply to [the Permittee], as described in 40 C.F.R. 60.4211(a).

[12] In this permit, "Administrator" means EPA.

32. [A Permittee that] must comply with the emission standards specified in [condition 23], must demonstrate compliance according to the requirements specified in [conditions 32.1 through 32.3], as described in 40 C.F.R. 60.4211(d).

32.1 Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in [condition 33], as described in 40 C.F.R. 60.4211(d)(1).

32.2 Establishing operating parameters to be monitored continuously to ensure the stationary ICE continues to meet the emission standards. [The Permittee] must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in [conditions 32.2a through 32.2e], as described in 40 C.F.R. 60.4211(d)(2);

a. Identification of the specific parameters you propose to monitor continuously;

b. A discsussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

c. A discussion of how [the Permittee] will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

d. A discussion identifying the methods and the instruments you will use to monitor these paramters, as well as the relative accuracy and precision of these methods and instruments; and

e. A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

32.3 For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in [condition 33], as described in 40 C.F.R. 60.4211(d)(3).

33. [A Permittee that owns or operates a] stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to [conditions 33.1 through 33.4], as described in 40 C.F.R. 60.4213.

33.1 Each performance test must be conducted according the requirements of 40 C.F.R. 60.8 and under the specific conditions that this subpart specifies in table 7 [to Subpart IIII of Part 60]. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load, as described in 40 C.F.R. 60.4213(a).

33.2 [The Permittee] may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in [40 C.F.R.] 60.8(c), as described in 40 C.F.R. 60.4213(b).

33.3 [The Permittee] must conduct three separate test runs for each performance test required in [condition 33], as specified in [40 C.F.R.] 60.8(f). Each test run must last at least 1 hour, as described in 40 C.F.R. 60.4213(c).

33.4 To determine compliance with the percent reduction requirement, [the Permittee] must follow the requirements as specified in [conditions 33.4a through 33.4c], as described in 40 C.F.R. 60.4213(d).

a. [The Permittee] must use Equation 2 of [40 C.F.R. 60.4213(d)(1)] to determine compliance with the percent reduction requirement, as described in 40 C.F.R. 60.4211(d)(1).

b. [The Permittee] must normalize the NO_X or PM concentration at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of [40 C.F.R. 60.4213(d)(2)], as described in 40 C.F.R. 60.4213(d)(2).

c. If pollutant concentrations are to be corrected to 15 percent O_2, and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in [conditions 33.4c(i) through 33.4c(iii)], as described in 40 C.F.R. 60.4213(d)(3).

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2 [of 40 C.F.R. 60], and [Equation 4 in 40 C.F.R. 60.4213(d)(3)(i)], as described in 40 C.F.R. 60.4213(d)(3)(i).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 [using Equation 5 of 40 C.F.R. 60.4213(d)(3)(ii)], as described in 40 C.F.R. 60.4213(d)(3)(ii).

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 [and using Equation 6 of 40 C.F.R. 60.4213(d)(3)(iii)], as described in 40 C.F.R. 60.4213(d)(3)(iii).

d. To determine compliance with the NO_X mass unit emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of [40 C.F.R. 60.4213(e)], as described in 40 C.F.R. 60.4213(e).

e. To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of [40 C.F.R. 60.4213(f)], as described in 40 C.F.R. 60.4213(f).

34. [Permittees that own or operate] non-emergency stationary CI ICE that are greatrer than 2,237 kW (3,000 hp), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 kW (175 hp) and not certified, must meet the requirements of [conditions 34.1 and 34.2], as described in 40 C.F.R. 60.4214(a).

34.1 Submit an initial notification as required in [40 C.F.R. 60] 60.7(a)(1). The notification must include the information in [conditions 34.1a through 34.1e], as described in 40 C.F.R. 60.4214(a)(1).

a. Name and address of the owner or operator;

b. The address of the affected source;

c. Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

d. Emission control equipment; and

e. Fuel used.

34.2 Keep records of the information in [conditions 34.2a through 34.2d], as described in 40 C.F.R. 60.4214(a)(2).

a. All notifications submitted to comply with [Subpart IIII] and all documentation supporting any notification;

b. Maintenance conducted on the engine;

c. If the stationary CI ICE is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards;

d. If the stationary CI ICE is not a certified engine, documentation that the engine meets the emission standards.

35. Prior to December 1, 2010, [Permittees that own or operate] stationary CI engines located in Alaska not accessible by the Federal Aid Highway System should refer to 40 C.F.R. part 69 to determine the diesel fuel requirements applicable to such engines, as described in 40 C.F.R. 60.4216(a).

36. Table 8 to [Subpart IIII] shows which parts of the General Provisions in [40 C.F.R.] 60.1 to 60.19 apply to [the Permittee], as described in 40 C.F.R. 60.4218.

Maintenance Requirements

37. **Maintenance.** For Units 13 through 18 listed in Table 1, the Permittee shall

37.1 perform regular maintainance considering the manufacturer's or the operator's maintenance procedures;

37.2 keep records of any maintenance that would have a significant effect on emissions; the records may be kept in an electronic format; and

37.3 keep a copy of either manufacturer's or the operator's maintenance procedures.

Section 4 Stationary Source-Wide Requirements

38. **Air Pollution Prohibited.** No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property.

38.1 If emissions present a potential threat to human health or safety, the Permittee shall report any such emissions according to condition 48.

38.2 As soon as practicable after becoming aware of a complaint that is attributable to emissions from the facility, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of condition 38.

38.3 The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if

a. after an investigation because of a complaint or other reason, the Permittee believes that emissions from the facility have caused or are causing a violation of condition 38; or

b. the Department notifies the Permittee that it has found a violation of condition 38.

38.4 The Permittee shall keep records of

a. the date, time, and nature of all emissions complaints received;

b. the name of the person or persons who complained, if known;

c. a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of condition 38; and

d. any corrective actions taken or planned for complaints attributable to emissions from the stationary source.

38.5 In each semi annual operating report, the Permittee shall include a brief summary report which must include

a. the number of complaints received;

b. the number of times the Permittee or the Department found corrective action necessary;

c. the number of times action was taken on a complaint within 24 hours; and

d. the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.

38.6 The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

Section 5 General Source Test Requirements

39. **Requested Source Tests.** In addition to any source testing explicitly required by this permit, the Permittee shall conduct soruce testing as requested by the Department to determine compliance with applicable permit requirements.

40. **Test Deadline Extension.** The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

41. **Test Plans.** Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance, and must specify how the emission unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under condition 39 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

42. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and the time the source test will begin.

43. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit two copies of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results in the manner set out in condition 44. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

Section 6 General Recordkeeping, Reporting, and Compliance Requirements

44. **Certification.** The Permittee shall certify all reports, compliance certifications, or other documents submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete." Excess emission reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

45. **Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall send reports, compliance certifications, and other documents required by this permit to ADEC, Air Permits Program, 610 University Ave., Fairbanks, AK 99709-3643, ATTN: Compliance Technician. The Permittee may, upon consultation with the Compliance Technician regarding software compatibility, provide electronic copies of data reports, emission source test reports, or other records under a cover letter certified in accordance with condition 44.

46. **Information Requests.** The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke and reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the federal administrator.

47. **Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five years after the date of collection, including.

    47.1 Copies of all reports and certifications submitted pursuant to this section of the permit.

    47.2 Records of all monitoring required by this permit, and information about the monitoring including:

    a. calibration and maintenance records, original strip chart or computer-based recordings for continuous monitoring instrumentation;

    b. sampling dates and times of sampling or measurements;

    c. the operating conditions that existed at the time of sampling or measurement;

    d. the date analyses were performed;

e. the location where samples were taken;

f. the company or entity that performed the sampling and analyses;

g. the analytical techniques or methods used in the analyses; and

h. the results of the analyses.

48. Excess Emissions and Permit Deviation Reports.

48.1 Except as provided in condition 38, the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:

a. in accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report

(i) emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable;

b. in accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that causes emissions in excess of a technology based emission standard;

c. report all other excess emissions and permit deviations

(i) within 30 days of the end of the month in which the emissions or deviation occurs or is discovered, except as provided in conditions 48.1c(ii) and 48.1c(iii);

(ii) if a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery unless the Department provides written permission to report under condition 48.1c(i); and

(iii) for failure to monitor, as required in other applicable conditions of this permit.

48.2 The Permittee must report using either the Department's on-line form, or if the Permittee prefers, the form contained in Attachment 2 of this permit. The Permittee must provide all information called for by the form that is used.

48.3 If requested by the Department, the Permittee shall provide a more detailed written report as requested to follow up an excess emissions report.

49. **Operating Reports.** During the life of this permit, the Permittee shall submit to the Department an original and two copies of an operating report by August 1 for the period January 1 to June 30 of the current year, and by February 1 for the period July 1 to December 31 of the previous year.

49.1 The operating report must include all information required to be in operating reports by other conditions of this permit.

49.2 If excess emissions or permit deviations that occurred during the reporting period are not reported under condition 49.1, either

a. The Permittee shall identify

(i) the date of the deviation;

(ii) the equipment involved;

(iii) the permit condition affected;

(iv) a description of the excess emissions or permit deviation; and

(v) any corrective action or preventive measures taken and the date of such actions; or

b. When excess emissions or permit deviations have already been reported under condition 48 the Permittee may cite the date or dates of those reports.

50. The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to

50.1 enter upon the premises where a emission unit subject to the permit is located or where records required by the permit are kept;

50.2 have access to and copy any records required by the permit;

50.3 inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

50.4 sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

Section 7 Terms to Make Permit Enforceable

51. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

    51.1 an enforcement action; or

    51.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

52. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

53. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

54. Compliance with permit terms and conditions is considered to be compliance with those requirements that are

    54.1 included and specifically identified in the permit; or

    54.2 determined in writing in the permit to be inapplicable.

55. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

56. The permit does not convey any property rights of any sort, nor any exclusive privilege.

Section 8 Permit Documentation

November, 2005	Application for Prevention of Significant Deterioration Construction Permit, New Power Plant Project.
February 27, 2006	Email from Al Bohn (HMH) to Sally Ryan (ADEC) clarifying the application.
March 1, 2006	Email from Al Bohn (HMH) to Sally Ryan (ADEC) containing vendor data for Cat C-9 generator.
March 2, 2006	Letter from Bill Walker (ADEC) to Chris Hladick (City of Unalaska), Incompleteness Finding.
May 10, 2006	Letter from Chris Hladick (City) to Bill Walker (ADEC), containing Response to Completeness Review and Addendum to the Prevention of Significant Deterioration Construction Permit Application.
May 17, 2006	Email from Sally Ryan (ADEC) to Al Bohn (HMH) requesting a revised SO_2 PSD applicability analysis.
May 19, 2006	Email from Al Bohn (HMH) to Sally Ryan (ADEC) – application supplement containing SO_2 emission spreadsheet.
June 5, 2006	Email from Al Bohn (HMH) to Sally Ryan (ADEC) containing fuel specifications.
June 6, 2006	Email from Alan Schuler (ADEC) to Al Bohn (HMH) Application is complete.
July 24, 2006	Letter from Chuck Salotti (Miratech) to Malay Jindal (MACTEC) including SCR cost quote.
August 9, 2006	Teleconference - Bill Walker (ADEC) requested documentation from City to support City's finding of no SCR as BACT for Phase 1. (Meeting notes transmitted to City on August 25, 2005.)
August 17, 2006	Letter from Mike Hubbard (Financial Engineering Company) to Chris Hladick (City) transmitting SCR Rate Impact Analysis.
August 22, 2006	Email from Sally Ryan (ADEC) to Al Bohn (HMH) regarding PM PSD applicability.
September 15, 2006	Letter from Chris Hladick (City) to Bill Walker (ADEC) transmitting an application supplement.
September 18, 2006	Telephone conversation between Dave Burlingame (Electric Power Systems) and Sally Ryan (ADEC) clarifying rate august 17, 2006 Rate Impact Analysis.
September 19, 2006	Email from Sally Ryan (ADEC) to ACMP Participants – ACMP Scoping email.

September 22, 2006	Letter from Mike Hubbard (Financial Engineering Company) to Chris Hladick (City) transmitting revised SCR Rate Impact Analysis.
September 26, 2006	Spreadsheet prepared by Sally Ryan allocating DHPP SCR O&M cost provided by the City to "consumable" and "labor"
October 30, 2006	Email from Krista Thiemann (HMH) to Sally Ryan (ADEC) containing updated vendor data for Cat C-9 generator.
November 7, 2006	Email from Dave Burlingame (EPS) to Sally Ryan (ADEC) containing SCO Cost Estimates.
November 20, 2006	Email from Dave Burlingame (EPA) to Sally Ryan (ADEC) containing revised SCO cost estimate.
November 29, 2006	Preliminary Construction Permit No. AQ0215CPT02 and TAR.
December 7, 2006	Letter from Chris Hladik (City) to Bill Walker (ADEC) Subject: "City of Unalaska, Dutch Harbor Power Renovation Project – CO PSD Applicability Based on revised Wärtsilä CO Emission Rates"
December 29, 2006	City of Unalaska Comments on Preliminary Construction Permit No. AQ0215CPT02.

Section 9 Attachments

Attachment 1 - Visible Emissions Form

Visible Emissions Field Data Sheet

Certified Observer: ______________________________

Company &
Stationary Source: ____

Location: ____

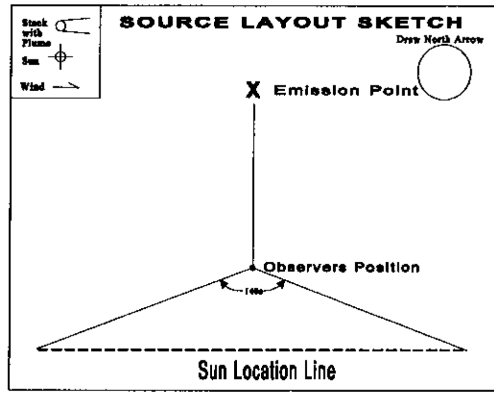
Test No.: ____________ Date: ____________

Source: ______________________________

Production Rate/Operating Rate: ______________________________

Unit Operating Hours: ______________________________

Hrs. of observation: ____________



Clock Time	Initial				Final
Observer location Distance to discharge					
Direction from discharge					
Height of observer point					
Background description					
Weather conditions Wind Direction					
Wind speed					
Ambient Temperature					
Relative humidity					
Sky conditions: (clear, overcast, % clouds, etc.)					
Plume description: Color					
Distance visible					
Water droplet plume? (Attached or detached?)					
Other information					

Visible Emissions Observation Record

Page ___ of ___

Company & Stationary Source ______________________________ Certified Observer______________________

Test Number ____________________________ Clock time_________________

Date:		Visibility reduction every 15 Seconds (Opacity)				Steam Plume (check if applicable)		Comments
Hr	Min	0	15	30	45	Attached	Detached	

Additional information:

_______________________________________ _______________________________________

Observer Signature and Date Certified By and Date

Data Reduction:

Duration of Observation Period (minutes) ________ Duration Required by Permit (minutes)_________

Number of Observations _____________________ Highest Six –Minute Average Opacity (%)______

Number of Observations exceeding 20 % ________

In compliance with three-minute aggregate opacity limit? (Yes or No) _________

In compliance with six-minute opacity limit? (Yes or No) _________

Average Opacity Summary

Set Number	Time Start—End	Opacity	
		Sum	Average

Attachment 2 - ADEC Notification Form[13]

Excess Emissions and Permit Deviation Reporting
State of Alaska Department of Environmental Conservation
Division of Air Quality

Stationary Source Name **Air Quality Permit Number**

Company Name

When did you discover the Excess Emissions/Permit Deviation?

Date: / / Time: :

When did the event/deviation?

Begin: Date: / / Time: : (please use 24hr clock)
End: Date: / / Time: : (please use 24hr clock)

What was the duration of the event/deviation: : (hrs:min) or days (total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for notification: (please check only 1 box and go to the corresponding section)

☐Excess Emissions Complete Section 1 and Certify
☐Deviation from permit conditions complete Section 2 and certify
☐Deviation from COBC, CO, or Settlement Agreement Complete Section 2 and certify

Section 1. Excess Emissions

(a) Was the exceedance ☐Intermittent or ☐Continuous

(b) Cause of Event (Check one that applies):

☐Start Up/Shut Down ☐Natural Cause (weather/earthquake/flood)
☐Control Equipment Failure ☐Scheduled Maintenance/Equipment Adjustments
☐Bad fuel/coal/gas ☐Upset Condition ☐Other

(c) Description

Describe briefly what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance.

(d) Emission unit(s) Involved:

Identify the emission units involved in the event, using the same identification number and name as in the permit. Identify each emission standard potentially exceeded during the event and the exceedance.

[13] Revised as of December 6, 2004

EU ID	Emission Unit Name	Permit Condition Exceeded/Limit/Potential Exceedance

(e) Type of Incident (please check only one):

☐Opacity   %
☐Fugitive Emissions
☐Marine Vessel Opacity
☐Other:
☐Venting   (gas/scf)
☐Emission Limit Exceeded
☐Failure to monitor/report
☐Control Equipment Down
☐Record Keeping Failure
☐Flaring

(f) Unavoidable Emissions:
Do you intend to assert that these excess emissions were unavoidable? ☐YES ☐NO
Do you intend to assert the affirmative defense of 18 AAC 50.235? ☐YES ☐NO

Certify Report (go to end of form)

Section 2. Permit Deviations

(a) Permit Deviation Type (check one only) (check boxes correspond with sections in permit)

☐Emission Unit Specific
☐General Source Test/Monitoring Requirements
☐Recordkeeping/Reporting/Compliance Certification
☐Standard Conditions Not Included in Permit
☐Generally Applicable Requirements
☐Reporting/Monitoring for Diesel Engines
☐Insignificant Emission Unit
☐Stationary Source-Wide
☐Other Section: (title of section and section # of your permit)

(b) Emission unit(s) Involved:
Identify the emission unit involved in the event, using the same identification number and name as in the permit. List the corresponding Permit condition and the deviation.

EU ID	Emission Unit Name	Permit Condition /Potential Deviation

(c) Description of Potential Deviation: Describe briefly what happened and the cause. Include the parameters/operating conditions and the potential deviation.

(d) Corrective Actions: Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence.

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name:______________________________Title______________________Date _____

Signature: __________________________________Phone number________________________

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ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

TECHNICAL ANALYSIS REPORT
for
Air Quality Control Construction Permit No. AQ0215CPT02

CITY OF UNALASKA
DUTCH HARBOR POWER PLANT

Power Plant Renovation Project

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Supervisor: Bill Walker
Date: Final – January 31, 2007

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Abbreviations/Acronyms

AAC .... Alaska Administrative Code
ADEC............................ Alaska Department of Environmental Conservation
AS .... Alaska Statutes
ASTM............................ American Society of Testing and Materials
C.F.R. .... Code of Federal Regulations
DHPP .... Dutch Harbor Power Plant
EPA .... Environmental Protection Agency
FITR .... Fuel Injection Timing Retard
MR&R........................... Monitoring, Recordkeeping, and Reporting
n/a .... Not Applicable
NESHAPS .... National Emission Standards for Hazardous Air Pollutants
NSPS .... New Source Performance Standards
PSD .... Prevention of Significant Deterioration
PTE............................... Potential to Emit
RIA............................... Rate Impact Analysis
RM .... Reference Method
SIC .... Standard Industrial Classification
SN .... Serial Number
TAR.............................. Technical Analysis Report
TBD.............................. To Be Determined

Units and Measures

bhp................................ brake horsepower or boiler horsepower
gr./dscf.......................... grains per dry standard cubic feet (1 pound = 7,000 grains)
dscf .... dry standard cubic foot
gph................................ gallons per hour
GW .... GigaWatt (electric) (= 10^6 kW)
hpy................................ hours per year
kW................................ kilowatts (electric)
lbs .... pounds
mmBtu.......................... million British thermal units
MW .... MegaWatt
ppm............................... parts per million
ppmv............................. parts per million by volume
tph................................. tons per hour
tpy................................. tons per year
wt% .... weight percent

Pollutants

CO .... Carbon Monoxide
HAPS .... Hazardous Air Pollutants
NO_X .... Oxides of Nitrogen
NO_2 .... Nitrogen Dioxide
NO .... Nitric Oxide
PM-10........................... Particulate Matter with an aerodynamic diameter less than 10 microns
S .... Sulfur
SO_2 .... Sulfur Dioxide
VOC .... Volatile Organic Compound

1. Introduction

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) basis for issuing Air Quality Control Construction Permit No. AQ0215CPT02 to the City of Unalaska (City) for the Dutch Harbor Power Plant (DHPP).

The City is planning to renovate the DHPP. The Department received the City's original application on November 14, 2005. The Department found this application incomplete on March 2, 2006. The Department deemed the application complete on June 5, 2006. The Department received application supplements through November 20, 2006.

2. Background

2.1. Stationary Source Description

The DHPP is a diesel electric power plant that provides electricity to the City. The existing DHPP consists of eight diesel electric generator sets ranging in size from 300 kiloWatts (kW) to 1,230 kW and three fuel storage tanks of 10,000 gallons capacity each. The eight existing generator sets are located in the old powerhouse.

The DHPP is a Prevention of Significant Deterioration- (PSD-) major stationary source because its Potential to Emit (PTE) exceeds 250 tons per year (tpy) of Nitrogen Oxides (NO_X). The DHPP operates under Operating Permit No. 215TVP01 Revision 1.

DHPP is located on the Aleutian Island Chain in Southwest Alaska. The City is not linked to a regional power grid, so it relies solely on electric power generated by DHPP.

Federal PSD and Alaska Air Quality Control Regulations designate the area adjacent to the DHPP as Class II. It is also a special protection area for Sulfur Dioxide (SO_2). The nearest Class I areas are the Bering Sea National Wildlife Refuge located 500 miles north of the DHPP, and the Simeonof National Wildlife Refuge located 300 miles northeast of the DHPP.

2.2. Project Description

This section describes the Project as described in the application. The Department's findings regarding the application are listed in Section 3.

The City proposes to construct a new power plant adjacent o the existing power plant. The new power plant will be built in two phases. In phase 1 the City will add:

(1) Two new diesel-fired Wärtsilä 12V32C generators rated at 5,211 kW each, Generators A and B (Units 13 and 14);[1]

(2) One Cat C-9 (black start) generator rated at 250 kW (Unit 17); and

(3) One 10,000-gallon fuel storage tank, Tank T4 (Unit 18).[2]

The new units will be housed in a new powerhouse building adjacent to the old powerhouse.

[1] The application refers to these units as Generators A and B. These are Units 13 and 14 in Construction Permit No. AQ0215CPT02 and this TAR.

[2] The application refers to this storage tank as Tank T4. This is Unit 18 in Construction Permit No. AQ0215CPT02 and this TAR.

As described in the application, during phase 1 Units 13 and 14 will operate unrestricted at 100 percent load, and Unit 17will operate no more than 500 hours per year. The City will operate two existing generators (Unit 7 (1,180 kW) and 8 (1,230 kW) listed in Operating Permit No. 215TVP01, Revision 1) in a limited capacity as backup (3,000 hour per year, each). The six other existing generators (Units 1 through 6) will be placed in emergency stand-by. All new and existing generators will use diesel fuel with a maximum sulfur content of 0.10 weight percent sulfur (wt%S). The phase 1 engines are required to provide power for the City's current load base 36,583,936 kilowatt-hours per year[3, 4] However, the City has provided "interruptible service to three large customers that either self-generated in the past of recently expanded operations."[5]

The construction of phase 2 depends on the City's ability to negotiate power supply agreements with commercial users in the area that are currently served by older, on-site diesel generators. During phase 2, the City will add two new diesel-fired Post Model Year 2007 generators; Generators C and D (Units 15 and 16)[6] (rated at about 5,211 kW each.

After phase 2 is complete, the City will limit Units 13 and 14 to 73.04 GigaWatt-hours per year[7] (GW-hr/yr), combined; and Units 15 and 16 to 36.52 GW-hr/yr, combined; and Unit 17 to 500 hours per year. NO_X emissions from Units 15 and 16 will be controlled consistent with New Source Performance Standards (NSPS), Subpart IIII standards (i.e. 90 percent control of NO_X and 60 percent of PM-10). Units 13, 14, and 17 will use diesel fuel with 0.10 wt%S. Units 15 and 16 will use fuel with a sulfur content of 15 parts per million (ppm) (0.0015 wt%S) in accordance with NSPS, Subpart IIII standards. All generators in the old plant (Units 1 through 8) will be retired.

The Power Plant Renovation Project (Project) is a modification to an existing stationary source.

2.3. Project Emissions Summary

The Department calculated project emissions for PSD applicability, minor permit applicability, and assessable emissions, for phase 1 and for phase 2. The Department used information in the construction permit application and application supplements, as well as the title V renewal application dated January 2005, with revisions as necessary. The Department's assumptions for calculating project emissions are listed below.[8]

3 Rate Impact Analysis prepared by the Financial Engineering Company dated September 22, 2006 (page 6) states "With the two new Wartsila units being added to the City system and placing much of its older, less efficient units in reserves, the City will have sufficient capacity for the City's current load base."

4 Rate Impact Analysis prepared by the Financial Engineering Company dated September 22, 2006 (page A-1 Item 7, Table 5 and Figure 2). The City indicates that the phase 1 "Sales without self-generators are assumed to be 36,583,936 kilowatt-hours per year, the amount incurred in the fiscal year ending June 30, 2006. No load growth is assumed." (See page A-1 item 7 and Table 5 of the RIA).

5 Rate Impact Analysis prepared by the Financial Engineering Company dated September 22, 2006 (page 2)

6 The application refers to these units as Generators C and D. These are Units 15 and 16 in Construction Permit No. AQ0215CPT02 and this TAR.

7 In this document GW-hr/yr means GigaWatt-hours of power generation per 12 consecutive months. The monitoring, recordkeeping, and reporting in the permit reflect the Departments intention that this limit is on a 12 consecutive month basis.

8 These assumptions pertain to the new Project emission calculations, they do not pertain to **past actual** emission estimates for Units 1 through 8 used for the PSD applicability analysis.

2.3.1. Phase 1 (Units 1 through 6, 7, 8, 13, 14, 17, and 18)

(1) Emission factors for Units 13 and 14are based on 100 percent of rated capacity. Fuel rate at 100 percent load as provided in the application, and shown in Table A-1 (Appendix A of this TAR).[9]

(2) For Unit 17, the emissions factors are worst case emission factors (for CO, VOC, and PM the worst case is 10 percent load; and for NO_X the worst case is 100 percent load).

(3) Fuel net heat content is 130,500 British thermal units (Btu) per gallon.

(4) SO_2 emissions based on mass balance calculations, assuming 7.1 pounds (lb) fuel per gallon. Emissions from all units based on fuel with 0.10 wt%S.

(5) NO_X, PM-10, CO, and VOC emission factors, and the source of the emission factors are shown in Table A-1 (Appendix A of this TAR). (Table A-1 also shows unit ratings, and emission calculation information for both phases 1 and 2.)

(6) Units 1 through 6 assumed to operate 500 hours per year (hpy) (emergency standby),[10] Units 7 and 8 operate 3,000 hpy each, Units 13 and 14 operate 8,760 hpy each, and Unit 17 operates 500 hpy.

(7) Unit 18 (Storage Tank) VOC emissions are 0.3 tpy.[11]

PSD Applicability Analysis: The Department estimated emissions using the assumptions listed above. Table 1 shows the potential to emit (PTE) for each new unit in phase 1 of the Project, and past actual emissions for Units 1 through 8. The emissions shown in this table do not include emissions from Units 9 through 12, which are not changed in this permit action.

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[9] The Department recognizes that CO emission rate may go up as load decreases. On December 7, 2006, the City provided manufacturer guaranteed emission factors for 100 percent and 75 percent load for the Wärtsilä 12V32C generators. The Department has included permit conditions to require either (1) CO source tests at 50 percent and 25 percent load, or (2) a manufacturer guaranteed emission factors at 50 percent load and 25 percent load, if Unit 13 or 14 operate more than a prescribed number of hours at less than 75 percent load, as described in Section 4.5 for CO PSD avoidance.

[10] Refer to EPA Guidance "Calculating Potential to Emit (PTE) for Emergency Generators" prepared by John Seitz, September 6, 1995.

[11] The construction permit application and supplements do not include supporting documentation for VOC emissions from Unit 18 (Tank T4). The November 2005 application indicates Units 9 through 11 (existing tanks) plus Unit 18 (new tank) VOC emissions are 0.4 tpy (see Table 4-1 on page 7). The Title V renewal application dated January 2005 indicates that Units 9 through 11 VOC emissions are 0.1 tpy (Part one, Page 11). Therefore, Unit 18 VOC emissions are 0.3 tpy.

Table 1 – Phase 1 PSD Applicability Analysis

Emission Unit No.	DHPP ID	Unit Rating	NO_X tpy	SO_2 tpy	PM-10 tpy	CO tpy	VOC tpy
1	Generator #1	300 kW	1.50	0.08	0.04	0.64	0.06
2	Generator #2	300 kW	1.50	0.08	0.04	0.64	0.06
3	Generator #3	600 kW	3.37	0.16	0.09	1.28	0.13
4	Generator #4	830 kW	8.05	0.21	0.11	1.67	0.18
5	Generator #5	620 kW	6.42	0.16	0.08	1.23	0.13
6	Generator #6	1,440 kW	11.6	0.37	0.19	2.86	0.30
7	Generator #8	1,180 kW	69.0	1.64	0.86	12.8	1.36
8	Generator #9	1,230 kW	35.4	1.84	0.97	14.4	1.53
13	Generator A	5,211 kW	684	19.5	9.41	49.5	16.1
14	Generator B	5,211 kW	684	19.5	9.41	49.5	16.1
17	Black Start	250 kW	0.79	0.06	0.17	0.61	0.45
18	Fuel Tank	10,000 gal	0.0	0.0	0.0	0.0	0.3
TOTAL			1506	43.6	21.4	135	36.7
Existing Power Plant Units 1-8 Actual Emissions FY04-FY05 Average[a]			455	7.6	7.9	117	11.3
Net Change			1051	36.0	13.5	18.0	25.4
PSD Applicability Threshold			40	40	15	100	40
Significant Net Emissions Increase?			**YES**	NO	NO	**NO**	NO

Table Notes:
[a] The Department obtained "Past Actual" emissions calculations for Units 1 through 8 from Appendix A of the November 2005 application. The Department verified the NO_X calculations and found them correct. The Department recalculated the PM emissions using the appropriate emission factor of 0.0573 lb/mmBtu (see Table A-1). The Department did not verify the City's calculation of past actual emissions for SO_2, CO, and VOC.

As shown in Table 1, phase 1 of the Project is subject to PSD review for NO_X.

Minor Permit Applicability: Phase 1 of this project needs a minor permit under 18 AAC 50.502(c)(2)(B) because it has an emission unit with a capacity of 10 million British thermal units per hour (mmBtu/hr) or more in an SO_2 special protection area. The Department also assessed applicability under 18 AAC 50.502(c)(3) shown in **Table 2**. The emissions shown in this table do not include emissions from Units 9 through 12, which are not changed in this permit action.

Table 2 –Phase 1 Minor Permit Applicability Analysis

Emission Unit No.	DHPP ID	Unit Rating	SO_2 tpy	PM-10 tpy
1	Generator #1	300 kW	0.08	0.04
2	Generator #2	300 kW	0.08	0.04
3	Generator #3	600 kW	0.16	0.09
4	Generator #4	830 kW	0.21	0.11
5	Generator #5	620 kW	0.16	0.08
6	Generator #6	1,440 kW	0.37	0.19
7	Generator #8	1,180 kW	1.64	0.86
8	Generator #9	1,230 kW	1.84	0.97
13	Generator A	5,211 kW	19.5	9.41
14	Generator B	5,211 kW	19.5	9.41
17	Black Start	250 kW	0.06	0.17
18	Fuel Tank	10,000 gal	0.0	0.0
TOTAL			43.6	21.3
Existing Power Plant PTE[a]			34.0	10.5
Change			9.6	10.8
Minor Permit 18 AAC 502(c)(3) Threshold			10	10
Over Minor Permit under 18 AAC 502(c)(3) Threshold?			NO	**YES**

Table Notes:
[a] The Department did not find existing stationary source SO_2 or PM-10 PTE in the application or application supplements. The Department calculated the existing SO_2 PTE emissions using mass balance equations assuming the fuel limits listed in Table 2 of Operating Permit No. 215TVP01 Revision 1 and a fuel sulfur content of 0.17 wt%S (condition 5 of Operating Permit No. 215TVP01 Revision 1). The resulting emissions agree with the SO_2 PTE listed in Operating Permit No. 215TVP01. The Department calculated existing PM-10 PTE using the fuel limits in Table 2 of Permit No. 215TVP01, Revision 1 and the emission factors shown in Appendix A of this TAR.

Table 2 shows that phase 1 of this project needs a minor permit under 18 AAC 50.502(c)(3) for PM-10, because the increase in PM-10 emissions is above the minor permit threshold. It does not need a permit under 18 AAC 50.502(c)(3) for SO_2. (The Department did not assess minor permit applicability for NO_X - for phase 1 a permit under 18 AAC 50.306 is already required for NO_X.)

Assessable Emissions: **Table 3** shows the assessable emissions for the DHPP after completion of phase 1 of the Project. This table includes emissions from existing Units 9 through 11 (0.1 tpy of VOC).[12]

Table 3 – Phase 1 Assessable Emissions

Pollutant	Emissions (tpy)
NO_X	1506
SO2	44
PM-10	21
CO	135
VOC	36
Total	1742

2.3.2. Phase 2 (Units 13 through 18)

(1) Emission factors for Units 13 through 16 are based on 100 percent of rated capacity. Fuel rate at 100 percent load as provided in the application, and shown in Table A-1 of this TAR.[13]

(2) For Unit 17, the emissions factors are worst case emission factors (for CO, VOC, and PM-10 the worst case is 10 percent load; and for NO_X the worst case is 100 percent load).

(3) Fuel net heat content is 130,500 Btu per gallon.

(4) SO_2 emissions based on mass balance calculations, assuming 7.1 lb fuel per gallon. For Units 13, 14, and 17, emissions based on fuel with 0.10 wt%S. For Units 15 and 16, emissions based on fuel with 0.0015 wt%S, to conform to 40 C.F.R 60, Subpart IIII.

(5) NO_X, PM-10, CO, and VOC emission factors, and the source of the emission factors are shown in Table A-1. (Table A-1 also shows unit ratings, and emission calculation information for both phases 1 and 2.)

(6) Units 13 and 14, combined, are limited to 73.04 GW-hr/yr.

(7) Units 15 and 16, combined, are limited to 36.52 GW-hr/yr .

(8) Unit 18 (Storage Tank) VOC emissions are 0.3 tpy.[14]

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[12] From Title V Operating Permit Renewal application dated January 2005, Part One, Page 11.

[13] The Department recognizes that CO emission rates may go up as load decreases. On December 7, 2006, the City provided manufacturer guaranteed emission factors for 100 percent and 75 percent load for the Wärtsilä 12V32C generators. The Department has included permit conditions to require either (1) CO source tests at 50 percent and 25 percent load, or (2) a manufacturer guaranteed emission factor at 50 percent and 25 percent load, if Unit 13 and 14 (combined), or Units 15 and 16 (combined), operate more than a prescribed number of hours at less than 75 percent load, as described in Section 4.5 for CO PSD avoidance.

[14] The construction permit application and supplements do not include supporting documentation for VOC emissions from Unit 18 (Tank T4). The November 2005 application indicates Units 9 through 11 (existing tanks) plus Unit 18 (new tank) VOC emissions are 0.4 tpy (see Table 4-1 on page 7). The Title V renewal application dated January 2005 indicates that Units 9 through 11 VOC emissions are 0.1 tpy (Part one, Page 11). Therefore, Unit 18 VOC emissions are 0.3 tpy.

PSD Applicability Analysis: The application contains a PSD applicability analysis for after completion of phase 2 of the Project (see Table 4-5 of the application.) The Department has revised the City's analysis as indicated in the assumptions listed above. Table 4 shows the PTE of each new unit after completion of phase 2 of the Project. The emissions shown in this table do not include emissions from Units 9 through 12, which are not changed in this permit action.

Table 4 – Phase 2 PSD Applicability Analysis

Emission Unit No.	DHPP ID	Unit Rating	NO_X tpy	SO_2 tpy	PM-10 tpy	CO tpy	VOC tpy
13	Generator A	5,211 kW	1095	31.2	15.1	79.2	25.8
14	Generator B	5,211 kW					
15	Generator C	5,211 kW	54.7	0.23	2.98	39.6	12.9
16	Generator D	5,211 kW					
17	Black Start	250 kW	0.79	0.06	0.17	0.61	0.45
18	Fuel Tank	10,000 gal	0.0	0.0	0.0	0.0	0.3
TOTAL			1150	31.5	18.3	119	39.5
Existing Power Plant Units 1-8 Actual Emissions FY04-FY05 Average[a]			455.2	7.6	7.9	117	11.3
Net Change			695	23.9	10.4	2	28.2
PSD Applicability Threshold			40	40	15	100	40
Significant Net Emissions Increase?			**YES**	NO	NO	NO	NO

Table Notes:
[a] The Department obtained "Past Actual" emissions calculations for Units 1 through 8 from Appendix A of the November 2005 application. The Department verified the NO_X calculations and found them correct. The Department recalculated the PM emissions using the appropriate emission factor of 0.0573 lb/mmBtu (see Table A-1). The Department did not verify the City's calculation of past actual emissions for SO_2, CO, and VOC.

As shown in Table 4, phase 2 of the Project is subject to PSD review for NO_X.

Minor Permit Applicability: Phase 2 of this project needs a minor permit under 18 AAC 50.502(c)(2)(B) because it has an emission unit with a capacity of 10 mmBtu/hr or more in an SO_2 special protection area. The Department also assessed applicability under 18 AAC 50.502(c)(3) shown in Table 5. This table does not include emissions from Units 9 through 12, which are not changed in this permit action.

Table 5 –Phase 2 Minor Permit Applicability Analysis

Emission Unit No.	DHPP ID	Unit Rating	SO_2 tpy	PM-10 tpy
13	Generator A	5,211 kW	31.2	15.1
14	Generator B	5,211 kW		
15	Generator C	5,211 kW	0.23	2.98
16	Generator D	5,211 kW		
17	Black Start	250 kW	0.06	0.17
18	Fuel Tank	10,000 gal	0.0	0.0
TOTAL			31.5	18.2
Existing Power Plant PTE[a]			34.0	10.5
Change			-2.5	7.7
Minor Permit 18 AAC 502(c)(3) Threshold			10	10
Over Minor Permit under 18 AAC 502(c)(3) Threshold?			**NO**	**NO**

Table Notes:
[a]The Department did not find existing stationary source SO_2 or PM-10 PTE in the application or application supplements. The Department calculated the existing SO_2 PTE emissions using mass balance equations assuming the fuel limits listed in Table 2 of Operating Permit No. 215TVP01 Revision 1 and a fuel sulfur content of 0.17 wt%S (condition 5 of Operating Permit No. 215TVP01 Revision 1). The resulting emissions agree with the SO_2 PTE listed in Operating Permit No. 215TVP01. The Department calculated existing PM-10 PTE using the fuel limits in Table 2 of Permit No. 215TVP01, Revision 1 and the emission factors shown in Appendix A of this TAR.

Table 5 shows that phase 2 of this project does not need a minor permit under 18 AAC 50.502(c)(3) for SO_2 or for PM-10, because the increases in emissions are below the minor permit thresholds. (The Department did not assess minor permit applicability for NO_X - for phase 2 a permit under 18 AAC 50.306 is already required for NO_X.)

Assessable Emissions: Table 6 shows the assessable emissions for the DHPP after construction of phase 2 of the Project. This table includes emissions from Units 9 through 11 (0.1 tpy of VOC.)[15]

[15] From Title V Operating Permit Renewal application dated January 2005, Part One, Page 11.

Table 6 – Phase 2 Assessable Emissions

Pollutant	Emissions (tpy)
NO_X	1150
SO_2	31
PM-10	18
CO	119
VOC	39
Total	1357

3. Department Findings

Based on a review of the application, the Department finds that:

(1) The City submitted an application to install four new diesel medium-speed generators (Units 13 through 16), one small diesel generator (Unit 17), and one new 10,000-gallon fuel storage tank (Unit 18). As described in the application, the Project will be constructed in two phases. (Phase 2 is dependant on the City's ability to negotiate power supply agreements with commercial users in the area that are currently served by older, on-site diesel generators.) As shown in **Table 1** and **Table 4**, phases 1 and 2 of the Project are classified as a PSD significant modification for NO_X.

(2) A project classified as a PSD significant modification is subject to review under **18 AAC 50.306,** which refers to federal regulations at 40 C.F.R 52.21. Regulations in **40 C.F.R. 52.21** require that an application for any new major or major modification of an existing major source contain:

   a. control technology review requirements in 40 C.F.R. 52.21(j), i.e. assessment of available control technology (BACT) for the PSD-triggered pollutants (this section further states that for phased projects, the BACT determination shall be reviewed and modified "as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement[16] of construction of each independent phase of the project");

   b. source impact analysis requirements in 40 C.F.R. 52.21(k) – i.e. an Alaska Ambient Air Quality Standard and increment analysis for the PSD-triggered pollutants;

   c. air quality analysis requirements in 40 C.F.R. 52.21(m), i.e. preconstruction monitoring for the PSD-triggered pollutants;

   d. source information requirements in 40 C.F.R. 52.21(n); and

   e. additional impact analysis requirements in 40 C.F.R. 52.21(o), i.e. analysis of the impact on soils, vegetation, and visibility.

(3) Under 40 C.F.R. 52.21(r), a PSD permit issued under 18 AAC 50.306, which refers to 40 C.F.R. 52.21 becomes invalid if construction is not commenced within 18 months of

[16] The word commence or commencement as it pertains to BACT has the meaning in 40 C.F.R. 52.21.

approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time.

(4) The Departments review of the City's NO_X BACT analysis is in Section 4.6. A summary of the Departments findings for BACT is shown in **Table 7**:

Table 7 – BACT Summary

Unit	Phase Installed	NO_X BACT
13	1	**13.6 g/kWh** (based on FITR and Aftercooling)
14	1	**13.6 g/kWh** (based on FITR and Aftercooling)
15	2	**1.36 g/kWh** (based on SCR or equivalent)
16	2	**1.36 g/kWh** (based on SCR or equivalent)
17	1	**5.75 g/kWh** (based on FITR and Aftercooling)

(5) Both phases of the Project require a minor permit under **18 AAC 50.502(c)(2)(B)** because they contain an emission unit with a rated capacity of 10 mmBtu per hour or more in an SO_2 special protection area established under 18 AAC 50.025(c). As described in 18 AAC 50.540(c)(2), an application for a minor permit classified under 18 AAC 50.502 must include a demonstration showing that the proposed potential emission will not interfere with the attainment or maintenance of the ambient air quality standards for SO_2.

(6) Phase 1 of the Project requires a minor permit under **18 AAC 50.502(c)(3)** for PM-10 because the emission increase is above 10 tpy. As described in 18 AAC 50.540(c)(2), an application for a minor permit classified under 18 AAC 50.502 must include a demonstration showing that the proposed potential emission will not interfere with the attainment or maintenance of the ambient air quality standards for PM-10.

(7) The City conducted ambient air quality analysis for NO_X, CO, SO_2, and PM-10 as required under **40 C.F.R. 52.21** and **18 AAC 50.544(c)(1)**. The Departments review of the ambient air quality assessment is included in Appendix B.

(8) For phase 1, the revised application includes requests to operate Units 1 through 6 in emergency standby (presumes less than 500 hours per year, each); and to limit Units 7 and 8 (existing generators) to 3,000 hours per year each; and to limit Unit 17 (the Cat C-9 blackstart unit) to 500 hours per year.[17] If these operational limits were not in place the SO_2 PTE in **Table 1** would be 61.0 tpy[18] (rather than 43.6), PM-10 PTE would be 32.6 (rather than 21.4), CO would be 266 (rather than 135), and VOC PTE would be 50.0 tpy (rather than 36.7), assuming the limits included in Permit No. 215TVP01 (see **Table 8**).

[17] The application indicates that the City requests these ORLs under 18 AAC 50.225. These are not ORLs under 18 AAC 50.225, because the purpose of a limit under 18 AAC 50.225 is to avoid a permit altogether.

[18] Assuming 0.10 wt%S.

Phase 1 of the Project would be classified as a PSD significant modification for SO_2, PM-10, and CO. (Phase 1 of the Project is already classified as PSD significant for NO_X.) The limits do not allow the City to avoid minor permit classification under 18 50.502(c)(2)(B) for SO_2 and PM-10. Therefore, these limits are "Owner Requested Limits" (ORLs) under **18 AAC 50.508(5)** for SO_2, CO, and PM-10 PSD Avoidance.

(9) For phase 1, the fuel limit of **0.10 wt%S** is also an ORL under **18 AAC 50.508(5)** to avoid classification as a PSD significant modification. Assuming the limits listed in Item (8) are in place, the Department calculated that total SO_2 PTE would be 73.7 tpy at 0.17 wt%S (the existing fuel sulfur limit in Permit No. 215TVP01). The resulting "net change" would be 66.0 tpy (73.7 minus 7.6), which is well over the threshold of 40 tpy (see **Table 9**).

(10) For phase 2, the revised application includes requests to decommission all generators in the old plant (Units 1 through 8), limit Units 13 and 14, combined, to 73.04 GW-hrs per year; limit Units 15 and 16, combined, to 36.52 GW-hrs per year; and to limit Unit 17 to 500 hours per year. If these operational limits were not in place the SO_2 PTE in **Table 4** would be 100 tpy,[19] (rather than 31.5), PM-10 PTE would be 51.4 tpy[20] (rather than 18.3), CO PTE would be 365 (rather than 119), and VOC PTE would be 82.2 tpy (rather than 39.5) (see **Table 8**). Phase 2 of the Project would be classified as a PSD significant modification for SO_2, PM-10, CO, and VOC. (Phase 2 of the Project is already classified as PSD significant for NO_X.) The limits do not allow the City to avoid minor permit classification under 18 50.502(c)(2)(B) for SO_2 and PM-10. Therefore, these limits are ORLs under **18 AAC 50.508(5)** for SO_2, PM-10, CO, and VOC PSD Avoidance.

(11) For phase 2, the fuel limits of **0.10 wt%S** for Units 13 and 14, and **0.0015 wt%S** for Units 15 and 16 are ORLs under **18 AAC 50.508(5)** to avoid classification as a PSD significant modification for SO_2. Assuming the limits listed in Item (10) are in place, the Department calculated that total SO_2 PTE would be 79.7 tpy at 0.17 wt%S (the existing fuel sulfur limit in Permit No. 215TVP01). The resulting "net change" would be 72.1 tpy (79.7 minus 7.6), which is well over the PSD threshold of than 40 tpy see **Table 10**).

(12) All industrial processes and fuel burning equipment in this permit are subject to state Air Quality Control standards in 18 AAC 50.055(a)(1) for visible emissions, 18 AAC 50.055(b)(1) for PM emissions, and 18 AAC 50.055(c) for SO_2.

(13) DHPP is located in the Aleutians West Coastal District. The Project is consistent with the Alaska Coastal Management Program (ACMP) through AS 46.40.040(b)(1). The Department notified the local district and resource agencies of the permit action on September 19, 2006. The local district and resource agencies did not request additional ACMP review.

(14) The City's application and subsequent submittals for a construction permit satisfy the requirements for a PSD construction permit application contained in 18 AAC 50.306 and 40 C.F.R. 52.21.

[19] Assuming 0.10 wt%S for Units 13 and 14, and 0.0015 wt%S for 15 and 16.

[20] Assuming PM emission factor for Units 15 and 16 is 0.074 g/kW-hr (a 60 percent reduction from vendor supplied emission factor of 0.187 g/kW-hr, as required by 40 C.F.R. 60 Subpart IIII).

(15) The City's application also included elements for a minor permit application listed in 18 AAC 50.540.

4. Technical and Regulatory Basis for Permit Requirements

4.1. Cover Page

The cover page identifies the stationary source, the project, the permittee, and contact information. This information is required for each minor permit issued under 18 AAC 50.542, as described in 18 AAC 50.544(a).

4.2. Assessable Emissions

Emission fee requirements are required for each minor permit issued under 18 AAC 50.542, as described in 18 AAC 50.544(a). The Department includes emission fee requirements Title I permits if the Title I permit changes assessable emissions.

4.3. Emission Unit Inventory and Authorization

The emission unit inventory is for informational purposes only. The authorization condition in the permit contains federal requirements for project approval listed in 40 C.F.R. 52.21(r)(2) concerning project construction timing.

The inventory is also necessary under 18 AAC 50.544(h)(2).

4.4. State Emission Standards

The Department included State emission standards in the permit. Because the City did not request that the Department incorporate this construction permit into the operating permit as an administrative amendment,[21] this permit does not include the on-going monitoring, recordkeeping, and reporting (mr&r) that would be necessary specifically for a **Title V operating permit or under Compliance Assurance Monitoring rule.**[22] (Because the City did not request an integrated review, the City can not operate under this permit upon issuance, as described under Section 9 of this TAR.)

As described in 18 AAC 50.544(c)(2), a minor permit classified under 18 AAC 50.502(c) must include performance tests for emission limits under 18 AAC 50.055 (state emission standards).

<u>**Visible Emissions**</u>

Emission Units 13 through 17 are liquid fuel burning equipment subject to the state visible emissions standard in 18 AAC 50.055(a)(1). The City did not include a visible emissions compliance demonstration for any of these units in the application, so the Department included an initial performance test and corresponding mr&r in the permit.

[21] The fee associated with a request to change a Title V permit by administrative amendment to incorporate…the requirements from a construction permit issued under 18 AAC 50.316 is $795. The fee to revise a Title V permit as a significant amendment is based on time and materials, and will include public notice costs.

[22] The Department has developed standard on-going mr&r conditions for state emission standards that it will incorporate into the operating permit during the Title V operating permit revision process. This statement does not apply to initial or on-going mr&r for Title I provisions established in this permit.

The Department will add necessary on-going mr&r during the operating permit revision to incorporate this construction permit.

Particulate Matter

The November 2005 application included a PM compliance demonstration in Appendix D for the Wärtsilä engines (represent Units 13 through 16) and the Cat C-9 Black Start engine (Unit 17). In their application, the City used Method 19 to calculate that the PM emission factor that corresponds to 0.05 gr/dscf is 0.2325 lb/mmBtu. However, they used 15 percent excess air in their calculations. The Department **recalculated** the PM emission factor that corresponds to the state standard with 10 percent excess air (typical for engines) as follows:

$$\left(\frac{9{,}190dscf}{mmBtu}\right)\left(\frac{0.05grains}{dscf}\right)\left(\frac{20.9}{20.9-10}\right)\left(\frac{1lb}{7{,}000grains}\right)=\frac{0.1259lb}{mmBtu}$$

Therefore, if an emission units' calculated emission rate is less than 0.1259 lb/mmBtu then it complies with the state standard.

The Wärtsilä engine has a guaranteed emission rate of 2.47 lb/hr at 100 percent load, and a fuel consumption rate of 313.8 gallons per hour (based on vendor data). PM emissions in lb/mmBtu are:

$$\left(\frac{2.47lb}{hr}\right)\left(\frac{hr}{313.8gallons}\right)\left(\frac{gallons}{130{,}500Btu}\right)\left(\frac{10^6\,Btu}{mmBtu}\right)=\frac{0.060lb}{mmBtu}$$

The resulting emission rate is less than 0.1259 lb/mmBtu so demonstrates compliance with the state PM standard. Because the applicant included initial compliance demonstrations in the application for the Wärtsilä engines, the Department did not require an initial performance test for the Wärtsilä engines in the permit.

Appendix D of the original application indicated that the PM emission factor for the Cat C-9 is 0.0496 lb/mmBtu (for PM-10) from AP-42 Table 3.4-2.[23] Vendor data submitted in an application supplement date October 30, 2006 indicates a worst case PM emission factor of 0.0159 lb/gal,[24] (at 10 percent load).

$$\left(\frac{0.0159lb}{gal}\right)\left(\frac{gallons}{130{,}500Btu}\right)\left(\frac{10^6\,Btu}{mmBtu}\right)=\frac{0.1218lb}{mmBtu}$$

This is less than 0.1259 lb/mmBtu, so demonstrates initial compliance with the state PM standard. Because the applicant included an initial compliance demonstration for the Cat C-9 engine, the Department did not require an initial performance test in the permit.

The Department will add necessary on-going mr&r during the operating permit revision to incorporate this construction permit.

[23] Table 3.4-2 is for large engines, and the emission factor should be 0.0620 lb/mmBtu for total filterable particulate, not filterable PM-10. If AP-42 were the only data available, the representative PM emission factor for the Cat C-9 engine to 0.31 lb/mmBtu for PM-10 (AP-42, Table 3.3-1, dated 10/96, for engines less than 600 hp). In Table 3.3-1, PM-10 is assumed to be the same as total particulate (see footnote b).

[24] Vendor data indicates an emission factor of 0.07 lb PM per hour at 10 percent load. The corresponding fuel consumption rate is 4.4 gallons per hour.

Sulfur Dioxide

This project shows initial compliance with the state sulfur standard based on the fuel sulfur limit of no more than 0.10 wt%S. The Department has previously calculated that fuel with less than 0.75 wt%S will comply with the state sulfur compound standard.

The Department will add necessary on-going mr&r during the operating permit revision to incorporate this construction permit.

4.5. PSD Avoidance

For phase 1, in the revised application the City assumes that Units 1 through 6 operate in emergency standby (presumes less than 500 hours per year, each); and includes requests to limit Units 7 and 8 (existing generators) to 3,000 hours per year each, and to limit Unit 17 (the Cat C-9 blackstart unit) to 500 hours per year. For phase 2, the revised application includes requests to decommission Units 1 through 8, limit Units 13 and 14, combined, to 73.04 GW-hr/yr; limit Units 15 and 16, combined, to 36.52 GW-hr/yr; and to limit Unit 17 to 500 hours per year. The application also includes a request to limit fuel sulfur to for all units 0.10 wt%S in phase 1, and for all units in phase 2 except for Units 15 and 16, which are limited to 0.0015 wt%S.

CO, SO_2, VOC and PM PSD avoidance

Table 8 shows stationary source emissions if **just** the fuel sulfur limit was implemented in the new permit. **In developing this table, the Department assumed fuel quantity limits listed in Permit No. 215TVP01, Revision 1, Table 2 for existing Units 1 – 8,[25] and no operating hour limits on new Units 13 – 18. Fuel sulfur 0.10 wt%S for all units.**

[25] The Department assumed the old limits in the Title V permit are in place when determining whether the project would be PSD without one or more new limits. This is because the Department does not rescind the old limits in Construction Permit No. AQ0215CPT02.

Table 8 – PSD Applicability Analysis with "Old" Title V Permit Fuel Quantity Limits and new Fuel Sulfur Limit (0.10 wt%S)

Emission Unit No.	DHPP ID	kWhr/yr	gal/yr	SO_2 tpy	PM-10 tpy	CO tpy	VOC tpy
1	Generator #1	1,090,620	84,638	0.60	0.32	4.69	0.50
2	Generator #2	1,090,620	84,638	0.60	0.32	4.69	0.50
3	Generator #3	3,708,108	284,462	2.02	1.06	15.8	1.67
4	Generator #4	5,129,549	373,509	2.65	1.40	20.7	2.19
5	Generator #5	3,831,712	273,234	1.94	1.02	15.2	1.60
6	Generator #6	9,422,957	673,874	4.78	2.52	37.4	3.96
7	Generator #8	7,721,590	504,235	3.58	1.89	28.0	2.96
8	Generator #9	7,601,621	535,238	3.80	2.00	29.7	3.14
13	Generator A	45,648,360	535,238	19.5	9.41	49.5	16.1
14	Generator B	45,648,360,	2,748,888	19.5	9.41	49.5	16.1
15	Generator C	45,648,360	2,748,888	19.5	9.41	49.5	16.1
16	Generator D	45,648,360	2,748,888	19.5	9.41	49.5	16.1
17	Black Start	2,190,000	2,748,888	2.01	3.23	10.7	0.98
18	Fuel Tank	n/a	n/a	0.0	0.0	0.0	0.3
TOTAL Phase 1 (Units 1-8, 13&14, 17, 18)				61.0	32.6	266	50.0
TOTAL Phase 2 (Units 13-18)				100.0	51.4	365	82.2
Existing Power Plant Units 1-8 Actual Emissions FY04-FY05 Average[a]				7.6	7.9	117	11.3
Net Change Phase 1				53.4	24.7	149	38.7
Net Change Phase 2				92.4	43.5	248	70.9
PSD Applicability Threshold				40	15	100	40
Significant Net Emissions Increase Phase 1?				**YES**	**YES**	**YES**	NO
Significant Net Emissions Increase Phase 2?				**YES**	**YES**	**YES**	**YES**

Table Notes:
[a] The Department obtained "Past Actual" emissions calculations for Units 1 through 8 from Appendix A of the November 2005 application. The Department verified the NO_X calculations and found them correct. The Department recalculated the PM emissions using the appropriate emission factor of 0.0573 lb/mmBtu (see Table A-1). The Department did not verify the City's calculation of past actual emissions for SO_2, CO, and VOC.

Therefore, the **phase 1 operational limits** are "Owner Requested Limits" under **18 AAC 50.508(5)** for SO_2, PM-10, and CO PSD Avoidance, and the **phase 2 operational limits** are "Owner Requested Limits" under **18 AAC 50.508(5)** for SO_2, PM-10, CO, and VOC PSD Avoidance.[26]

Table 9 and **Table 10** show project SO_2 emissions if all new operational limits listed above are in place and the fuel sulfur is 0.17 wt%S, as limited in Permit No. 215TVP01, Revision 1, for phase 1 and phase 2, respectively.

[26] The Department recognizes that CO emission rate may go up as load decreases. On December 7, 2006, the City provided manufacturer guaranteed emission factors for 100 percent and 75 percent load for the Wärtsilä 12V32C generators. The Department has included permit conditions to require either (1) CO source tests at 50 percent and 25 percent load, or (2) a manufacturer guaranteed emission factor at 50 percent and 25 percent load, if Unit 13 or 14 operate more than a prescribed number of hours at less than 75 percent load, as described in Section 4.5 for CO PSD avoidance.

Table 9 – SO_2 PSD Applicability Analysis with New Phase 1 Operational Limits and Old Fuel Sulfur Limit (0.17 wt%S)

Emission Unit No.	DHPP ID	Fuel Consumption gal/yr	SO_2 tpy
1	Generator #1	11,600	0.14
2	Generator #2	11,600	0.14
3	Generator #3	23,050	0.28
4	Generator #4	30,200	0.36
5	Generator #5	22,100	0.27
6	Generator #6	51,500	0.62
7	Generator #8	231,100	2.79
8	Generator #9	259,800	3.14
13	Generator A	2,748,888	33
14	Generator B	2,748,888	33
17	Black Start	9,500	0.1
18	Fuel Tank	n/a	0
TOTAL			73.7
Existing Power Plant Units 1-8 Actual Emissions FY04-FY05 Average[a]			7.6
Net Change			66
PSD Applicability Threshold			40
Significant Net Emissions Increase Phase 1?			**YES**

Table Notes:
[a] The Department obtained "Past Actual" emissions calculations for Units 1 through 8 from Appendix A of the November 2005 application. The Department verified the NO_X calculations and found them correct. The Department recalculated the PM emissions using the appropriate emission factor of 0.0573 lb/mmBtu (see Table A-1). The Department did not verify the City's calculation of past actual emissions for SO_2, CO, and VOC.

Table 10 – SO_2 PSD Applicability Analysis with New Phase 2 Operational Limits and Old Fuel Sulfur Limit (0.17 wt%S)

Emission Unit No.	DHPP ID	Fuel Consumption gal/yr	SO_2 tpy
13	Generator A	4,398,379	53.1
14	Generator B		
15	Generator C	2,199,190	26.5
16	Generator D		
17	Black Start	9,500	0.1
18	Fuel Tank	n/a	0
TOTAL			79.7
Existing Power Plant Units 1-8 Actual Emissions FY04-FY05 Average[a]			7.6
Net Change			72.1
PSD Applicability Threshold			40
Significant Net Emissions Increase Phase 2?			**YES**

Table Notes:
[a] The Department obtained "Past Actual" emissions calculations for Units 1 through 8 from Appendix A of the November 2005 application. The Department verified the NO_X calculations and found them correct. The Department recalculated the PM emissions using the appropriate emission factor of 0.0573 lb/mmBtu (see Table A-1). The Department did not verify the City's calculation of past actual emissions for SO_2, CO, and VOC.

Therefore, **fuel sulfur content** limits in phase 1 and phase 2 are "Owner Requested Limits" under **18 AAC 50.508(5)** for SO_2 PSD Avoidance.

Specific Requirements for CO PSD Modification Avoidance

In their original application, the City assumed AP-42 emissions factors for CO. As a result, the project was initially classified as a PSD major modification for CO. On December 7, 2006, the City provided manufacturer guaranteed emission factors for 100 percent and 75 percent load for the Wärtsilä 12V32C generators. However, the Department recognizes that CO emission rate may go up as load decreases. The Department has included permit conditions to keep CO emissions below the PSD modification threshold for phase 1 and phase 2. The permit requires either (1) CO source tests at 50 percent and 25 percent load, or (2) a manufacturer guaranteed emission factor at 50 percent and 25 percent load, if units operate more than a prescribed number of hours at less than 75 percent load. The permit does not require the City to calculate CO emissions unless they operate over the prescribed number of hours at loads less than 75 percent.

Phase 1 - The permit limits the CO emissions from Units 13 and 14 to 180 tpy, calculated as follows:

Table 11 –Phase 1 PSD Applicability Analysis, Assuming Maximum Emissions from Units 13 and 14

Emission Unit No.	CO tpy
1 - 8	35.5
13 & 14	178
17	0.61
TOTAL	214
Existing Power Plant Units 1-8 Actual Emissions FY04-FY05 Average[a]	117
Net Change	97.0
PSD Applicability Threshold	100
Significant Net Emissions Increase Phase 1?	NO

The Department calculated that the City could operate a maximum of 39.2 percent of the time at loads below 75 percent, and still avoid PSD for CO as follows:

(1) CO emission rate for Wärtsilä 12V32C engines operated at greater than or equal to 75 percent load is 11.3 lb/hr, based on manufacturer guarantee dated December 7, 2006. (CO PTE using 11.3 lb/hr is 135 tpy, as shown in **Table 1**.)

(2) CO emissions rate for Wärtsilä 12V32C engines operated at less than 75 percent load is 0.85 lb/mmBtu, based on AP-42 Table 3.4-2, dated 10/96. (CO PTE using AP-42 is 343 tpy, assuming fuel net heat content is 130,500 British thermal units (Btu) per gallon, and a fuel consumption rate of 313.8 gal/hr, as indicated in the November 29, 2006 preliminary TAR Table 1)

(3) Calculate percent of time:

$$7.3\,mo/12\,mo\,(135\,tpy) + 4.7\,mo/12\,mo\,(343\,tpy) - 117\,tpy = 99.5\,tpy$$

$$4.7/12 = 39.2\,percent\,(say\,39)$$

The Department will require a CO source test to verify the emission factor at less than 75 percent when the City approaches 39 percent of operating time at low loads as follows:

(1) The maximum operating time for one unit during a three month time period is 2,160 hours (for simplification, assumed 100 percent load):

$$(3\,mo)\left(30\,days/_{mo}\right)\left(24\,hr/_{day}\right) = 2{,}160\,hours$$

(2) 39 percent of 2,160 hours is 842 hours, and 90 percent of 842 is 758 hours per three months.

Phase 2 - The permit limits the CO emissions from Units 13 though 16 to 215 tpy, calculated as follows:

Table 12 –Phase 2 PSD Applicability Analysis, Assuming Maximum Emissions from Units 13 through 16

Emission Unit No.	CO tpy
13 - 14	213
17	0.61
TOTAL	214
Existing Power Plant Units 1-8 Actual Emissions FY04-FY05 Average[a]	117
Net Change	97
PSD Applicability Threshold	100
Significant Net Emissions Increase Phase 1?	NO

The Department calculated that the City could operate a maximum of 39 percent of the time at loads below 75 percent, during phase 2 and still avoid PSD for CO as follows:

(1) CO emission rate for Wärtsilä 12V32C engines operated at greater than or equal to 75 percent load is 11.3 lb/hr, based on manufacturer guarantee dated December 7, 2006. (CO PTE using 11.3 lb/hr is 119 tpy, as shown in **Table 4**.)

(2) CO emissions rate for Wärtsilä 12V32C engines operated at less than 75 percent load is 0.85 lb/mmBtu, based on AP-42 Table 3.4-2, dated 10/96. (CO PTE using AP-42 is 366 tpy, assuming fuel net heat content is 130,500 British thermal units (Btu) per gallon, and a fuel consumption rate of 313.8 gal/hr, as indicated in the November 29, 2006 preliminary TAR Table 4)

(3) Calculate percent of time:

$$7.3\,mo/_{12\,mo}(119\,tpy) + 4.7\,mo/_{12\,mo}(366\,tpy) - 117\,tpy = 98.7\,tpy$$

$$4.7/_{12} = 39.2\,percent\,(say\,39)$$

The Department will require a CO source test to determine the emission factor at less than 75 percent when the City approaches 39 percent of operating time at low loads as follows:

(1) The maximum operating time for the phase 1 units (combined) during a three month time period is 3,504 hours (for simplification, assumed 100 percent load):

$$(3\,mo)\left(\frac{yr}{12\,mo}\right)\left(\frac{73{,}040{,}000\,kW-hr}{yr}\right)\left(\frac{1}{5{,}211\,kW}\right)=3{,}504\,hours$$

(2) 39 percent of 3,504 hours is 1,367 hours, and 90 percent of 1,367 is **1,230** hours per three months for phase 1 engines.

(3) The maximum operating time for the phase 2 units (combined) during a three month time period is 1,826 hours (for simplification, assumed 5,000 kW engines at 100 percent load):

$$(3\,mo)\left(\frac{yr}{12\,mo}\right)\left(\frac{36{,}520{,}000\,kW-hr}{yr}\right)\left(\frac{1}{5{,}000\,kW}\right)=1{,}826\,hours$$

(4) 39 percent of 1,826 hours is 712 hours, and 90 percent of 712is **641** hours per three months.

4.6. Best Available Control Technology (BACT)

As defined in 40 C.F.R. 52.21(b)(12), best available control technology (BACT) means:

> *an emissions limitation (including a visible emission standard) based on the maximum degree pf reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, or techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emission of any pollutant which would exceed the emissions allowed by any applicable standard under 40 C.F.R. parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emission unit would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

Regulations in 40 C.F.R. 52.21 require that any new major source or major modification of an existing major source apply of BACT for each regulated pollutant that would be emitted in significant amounts. For phase 1 of the Project, Units 13, 14, and 17 are subject to BACT for NO_X, and for phase 2 Units 15 and 16 are subject to BACT for NO_X.

In their application, the City did not look at BACT in terms of phase 1 and phase 2. It appears that they did the economic analyses based on the entire project (i.e. assuming completion of phase 2). The City submitted subsequent information for phase 1, but not for phase 2. The Department has separated the BACT assessment into the two phases, as there is possibility that the City will never construct phase 2. The following sections contain the Departments review of the City's BACT assessments and final BACT determinations.

Phase 1 (Units 13, 14, and 17) NO_X BACT Assessment

The City included a top-down assessment of NO_X BACT for Stationary Diesel Generators in their November 2005 application. In May 2006, the City revised the project scope for phase 1, which changed assumptions for the BACT analysis (however they did not revise their BACT assessment).

In their application, the City considered the following controls, listed in order of control efficiency:

(1) Selective Catalytic Reduction (SCR);

(2) Selective Non-Catalytic Reduction;

(3) Fuel Injection Timing Retard (FITR);

(4) Water Injection;

(5) Aftercooling;

(6) Low Emission Combustion;

(7) Exhaust Gas Recirculation;

(8) Fuel Conversions; and

(9) Good air Pollution Control Practices

The November 2005 application contains a description of each technology. The City found that only SCR, FITR, and aftercooling to be available and technologically feasible technologies. In the November 2005 application, the City concluded that the combination of FITR and aftercooling is BACT for NO_X for Units 13 and 14. They rejected SCR based on economic infeasibility, which they estimated would cost between $1,952 per ton of NO_X removed to $2,249 per ton of NO_X removed. In an initial review of the City's November 2005 BACT analysis, the Department revised the City's BACT analysis (including the change in project scope) and concluded that SCR was NOT economically infeasible as BACT for NO_X for Units 13 and 14 for phase 1 of the Project.

In response to the Departments initial finding, the Financial Engineering Company (on behalf of the City) prepared a Rate Impact Analysis (RIA) dated August 17, 2006 and revised on September 22, 2006. This analysis updated and refined SCR costs, and projected the impact on the City's electric rates in terms of dollar per kW-hour ($/kWhr) if SCR is required for Units 13 and 14 in phase 1. An itemized list of the capital costs of SCR are provided in Table 1 of the September 22, 2006 RIA. Table 5 of the RIA shows the SCR operation and maintenance (O&M) costs used to develop the $/kWhr cost of SCR. The report does not include an itemized list of costs used to develop the SCR operation and maintenance costs but does include a list of assumptions on page A-1. The list of assumptions indicates that the rate impact analysis is based on sales (without self generators) of 36,583,936 kWh per year for two generators, and that this is the existing load.

The Department calculated the cost of SCR on a dollar per ton ($/ton) of NO_X removed basis, using the City's updated information, as follows:

(1) SCR Construction (Capital) Cost: $5,417,760 (for two units, from Table 1 of September 22, 2006 RIA)

(2) Capital Recovery Factor: 0.1627 from Table 6-2 of the City's November 2005 application. The City assumed period of 10 years and interest rate of ten percent

(3) Annual Capital Cost: $881,470 ($5,417,60 * 0.01627 = $881,470)

(4) Annual O&M Costs: $1,200,551 (average for years 2009 through 2013 from Table 5 of September 22, 2006 RIA)

(5) Total Annual Cost: $2,082,021 ($881,470 + $1,200,551 = $2,082,021)

(6) Annual NO_X removed (assuming 90 percent removal efficiency): 1,231 tons (2 units * 684 tons per unit * 0.9 = 1,231 tons)

(7) Cost in $ per ton removed: $1,690/ton ($2,082,021/1,231 tons = $1,691/ton)

The Departments review of the City's capital and O&M cost estimates is discussed below. However, even using the City's estimates, it is clear that $1,691/ton of NO_X removed is economically feasible for Alaska.

However, the City is subject to some unique geographical and economic characteristics such as:

(1) the City is not connected to an outside power grid, or to other utilities;

(2) the City does not have access to large scale alternative power generation options (continuous hydro-power, geothermal energy, and wind energy) at this time;

(3) DHPP is a publicly owned, non-profit operation; and

(4) the City of Unalaska has a population of about 4,400,[27] which is relatively small (compared to a typical electric utility in the lower 48) that would bear the cost of any pollution control device.

DHPP residential customers currently pay $0.239/kWh[28] for electricity (after adjusting for Power Cost Equalization or PCE).[29] As established by the Department of Energy, the "Representative Average Unit Cost" of electricity for a residential user is $0.0981/kWh.[30] So, a residential customer of DHPP pays 244 percent of the national average, even after PCE. For further comparison, the US Department of Agriculture, Rural Utilities Service provides grants to

[27] From the City's website at http:www.unalaska-ak.us

[28] From Alaska Department of Commerce, Community, and Economic Development, Division of Community Advocacy website at: http://www.commerce.state.ak.us/dca/commdb/CF_BLOCK.cfm

[29] PCE Report at http://www.commerce.state.ak.us/dca/pub/PCE2005.xls.

[30] Federal Register, Volume 71, No. 38, Monday, February 27, 2006. Available on the web at: http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/pdf/E6-2741.pdf.

communities with extremely high costs, which they have designated as 275 percent of the national average.[31]

Because of the unusual circumstances cited above, the Department finds it is appropriate to look at the cost of SCR per ratepayer. The City's Rate Impact Analysis revised on September 22, 2006 includes the projected cost of electrical power in $/kW-hr for the years 2006 through 2013, and the projected costs of SCR. These results are shown below in **Table 13**. The Department has some concerns about the City's cost estimates upon which the calculations are based. Therefore, the Department prepared **Table 15**, which shows that the expected rate increase due to SCR as revised by the Department (i.e. with reduced capital and O&M costs). **Table 13** and **Table 15** do not consider the effect of PCE.

Table 13 – Operating Expenses with SCR based on City's Costs

	2009	2010	2011	2012	2013
SCR Depreciation[a]	$270,888	$270,888	$270,888	$270,888	$270,888
Interest[a]	$392,788	$383,465	$373,466	$362,743	$351,242
O&M[a]	$1,021,278	$1,195,159	$1,228,026	$1,261,796	$1,296,496
Total	$1,684,954	$1,849,512	$1,872,380	$1,895,427	$1,918,626
Cost per KW-hr w/ SCR	$0.046	$0.051	$0.051	$0.052	$0.052
Avg Cost ($/kWh)[a]	$0.312	$0.318	$0.323	$0.329	$0.335
Increase due to SCR	14.7%	16.0%	15.7%	15.8%	15.5%

Table Notes:
[a] From Table 5, September 22, 2006 Rate Impact Analysis.

Department Review of Phase 1 NO_X BACT Assessment

The City included the capital cost of the urea building and the cost to enlarge the powerhouse to accommodate SCR in phase 1. The Department disagrees with this assumption. The City has requested authority to add two additional engines in phase 2 of the project. In their application, the City based compliance demonstrations and emission estimates on engines with a cylinder displacement greater than 30 liters, therefore subject to Subpart IIII. To comply with NSPS Subpart IIII, the City will need to reduce NO_X emissions by 90 percent for these phase 2 engines, regardless of the BACT determination for the phase 1 engines. At the present time, the only emissions control technology that is capable of reducing emissions by that amount is SCR.) For the purpose of the NO_X BACT cost estimate the costs for the urea building and any necessary expansion of the powerhouse to accommodate the emissions control system should therefore be assigned to phase 2. The Department has revised the capital cost to reflect this.

The Department also reviewed the City's O&M costs. There is no list in the application itemizing the costs that make up these O&M costs. For comparison, the Department referred to cost estimates used for SCR in the NO_X BACT analysis for the Nome Joint Utility System (NJUS) Power Plant (Permit No. 210CP02). Annual O&M costs for NJUS, and the comparable cost for DHPP are shown in **Table 14**.

[31] Federal Register, Volume 69, No. 15, January 23, 2004. Available on the web at: http://www.epa.gov/fedrgstr/EPA-IMPACT/2004/January/Day-23/i1471.htm

Table 14 – Comparison of NJUS O&M Costs to DHPP O&M Costs

Cost Category	NJUS[a,c] ($/year)	DHPP[b] ($/year)
Consumables	$905,547	$977,939
Labor	$167,521	$319,592

Table Notes:
[a] The costs presented here reflects the Departments revised costs for NJUS used in the BACT assessment for Permit No. 210CP02 (not necessarily the costs provided by NJUS).
[b] The Department back calculated the costs in this column using information provided in the "List of Assumptions" in the RIA.
[c] NJUS has three catalysts. The numbers shown here represent two catalysts.

Specifically, the Department questions the following items from the "List of Assumptions" on Page A-2 of the RIA.

(1) Item 26 indicates an **incremental station service load** of 547,260 kWhr/yr, due to SCR. According to Table 2 of the RIA, this incremental service load is due to building heat, lights, process heater 1, process heater 2, softener, etc, and heat trace system. This incremental load equates to 30,403 gallons of fuel per year. Using the City's assumed cost of $2.66/gal of fuel (Item 9 on page A-1 of the RIA), the annual cost is $80,872. The report does not contain documentation for this high energy cost. The Department notes that a previous submittal (EPS, August 8, 2006) indicates that the cost for process heater 2 is based on "heating costs required to keep the urea solution over 100°[Fahrenheit]". According to a representative from Miratech, it is only necessary to maintain the urea solution at 50°Fahrenheit (or less depending on concentration). Further, with the process heaters keeping the urea at temperature, why is there an additional cost to heat the building? (The Department included this under "Consumables" in **Table 14**.)

(2) Item 27b indicates an annual catalyst replacement cost of $67,200 per year (including labor), from 2nd year on. This is based on replacement cost of $60,000 per layer, one layer replaced per year, and 60 hours of labor at $120/hour. This seems high considering the estimated catalyst replacement cost for NJUS was $48,000 for two units). (The Department included $60,000 of this cost under "Consumables" in **Table 14.**) In addition, information from Miratech indicates an annual cost of about $24,800 for two catalysts.

(3) Item 27c indicates normal maintenance for SCR's is two person years for two units, at a rate of $75/hr. Assuming a person-year is 2,080 hours per year results in an annual cost for "normal maintenance" of $312,000/year, which seems high considering the estimated total annual labor costs for NJUS were $167,521.

The Department revised the costs as follows:

(1) The capital costs for the urea building and the powerhouse expansion are assigned to phase 2.

(2) The incremental station service load, the catalyst replacement cost, and the cost for normal maintenance are all reduced by 50 percent. Reduces O&M costs by $230,036 ($67,200 + 312,000 + $80,872)/2 = $230,036).

The resulting capital cost is $3,447,840, and O&M costs are $791,242, $965,123, $997,990, $1,031,760, and $1,066,460 from 2009 to 2013 respectively. The cost in $/kWh, assuming sales of 36,583,936 kWh (from September 22, 2006 RIA), is shown in **Table 15**

Table 15 – Operating Expenses with SCR with reduced Capital and O&M Costs

	2009	2010	2011	2012	2013
SCR Depreciation[a]	$172,392	$172,392	$172,392	$172,392	$172,392
Interest[b]	$258,588	$258,588	$258,588	$258,588	$258,588
O&M[c]	$791,242	$956,123	$997,990	$1,031,760	$1,066,460
Total	$1,222,222	$1,396,103	$1,428,970	$1,462,740	$1,497,440
Cost w/ SCR ($/kWh)	0.033	0.038	0.039	0.040	0.041
Cost w/o SCR ($/kWh)	$0.312	$0.318	$0.323	$0.329	$0.335
Increase due to SCR	10.6%	11.9%	12.0%	12.2%	12.2%

Table Notes:
[a] SCR Depreciation over 20 years: $3,477,840/20 years = $172,392
[b] The Department used a rough estimate of the interest, assuming 7.5 percent interest (capital cost times 7.5 percent)
[c] From Table 5, September 22, 2006 Rate Impact Analysis reduced by $230,036

In summary, using the City's number, the average cost per kWh for SCR for 2009 through 2013 is **$0.050/kWh**, an average increase of about **15.5 percent**. For a family that uses 500 kWh/month, the addition of SCR would cost $25.0/month and $300/year. For a family that uses 1,000 kWh/month, the additional cost is $50/month and $600/year.

Using the Department's adjusted costs, the average cost per kWh for SCR for 2009 through 2013 is **$0.038/kWh**, an average increase of about **11.8 percent**. For a family that uses 500 kWh/month, the addition of SCR would cost $19.0/month and $228/year. For a family that uses 1,000 kWh/month, the additional cost is $38/month and $456/year.

Either way, the Department agrees with the City that an increase of this size inordinately affects the City's ratepayers and rejects SCR on this basis. The Department determines that BACT for Unit 13 and 14 is FITR and aftercooling. The Wärtsilä 12V32C generators selected by the City come equipped with FITR. The emission rate associated with this technology is **13.6 g/kWh.** The Department calculated this emission rate based on the vendor guaranteed emission rate of 156 lb NO_X/hr at 100 percent load, and fuel rate of 313.82 gallons per hour at 100 percent load, provided in Appendix D of November 2005 application.

In their application, the City rejected SCR for Unit 17 (the Cat C-9 black start generator) based on cost considerations. They proposed FITR, in combination with aftercooling, as BACT for this unit. (As described in the application on page 16, this Cat C-9 engine is manufactured with FITR and an after-cooled turbocharger.) Given the small amount of NO_X emissions (less than one tpy, based on 500 hours per year), the Department agrees that SCR is not cost effective and the FITR, in combination with aftercooling, is BACT. The NO_X emission rate associated with this technology combination is **5.75 g/kWh,** based on vendor data provided in an application supplement dated October 30, 2006.

Phase 2 (Units 15 and 16) NO_X BACT Assessment

(As mentioned previously, the City did not provide a specific BACT assessment for phase 2. Their economic analysis of SCR considered the costs of SCR for **all four** units after construction of phase 2. This economic analysis is no longer pertinent as the City has submitted supplemental information on phase 1, and the Department has concluded that FITR and aftercooling is BACT for phase 1.)

In their application, the City assumed that Units 15 and 16 will be required to comply with (at that time) proposed NSPS Subpart IIII standard for NO_X that applies to compression ignition (CI) internal combustion engines with a displacement of greater than 30 liters per cylinder, i.e. a reduction in NO_X emissions of 90 percent. NSPS Subpart IIII is now final. The City assumed that the manufacturer would use dry catalytic controls to achieve this level of NO_X control. The City concluded that this **level of control** is BACT, "since this level of control is considered the emission limit that would apply." They assumed that they could meet this limit using dry controls.

The Department agrees that the engines will be subject to a NO_X emission reduction of 90 percent as an NSPS requirement. Because the BACT limit must be at least as stringent as NSPS, and additional reductions will not be cost effective,[32] the Department agrees with the City's conclusion that this level of control is BACT. The associated NO_X emission rate is **1.36 g/kWh**. However, the Department is unable to predict if dry catalytic controls will be a viable method to achieve this level of control at the time phase 2 is commenced.[33] At this time SCR is the only known viable method to achieve this level of control.

Under 40 C.F.R. 52.21(j)(4), for phased construction projects, "the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement[34] of construction of each independent phase of the project." As such, the permit includes a requirement to reassess BACT for either phase 1 or phase 2 if commencement[35] occurs more than 18 months after permit issuance.

Reassessment of BACT

Under 40 C.F.R. 52.21(j)(4), the Permittee must reassess NO_X BACT for a phased project if the phase starts more than 18 months after the original assessment. (Assume original assessment to be same date as permit issuance.) Therefore the City is required to reassess BACT for phase 2 if phase 2 commences[36] more than 18 months after permit issuance.

[32] The City performed a top-down BACT analysis for the phase 1 engines. The most stringent technologically available control technology was SCR, which has a control effectiveness of 90 percent.

[33] *Commence* as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has (i) begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or (ii) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time, as defined in 40 C.F.R. 52.21(b)(9).

[34] See footnote 33.

[35] See footnote 33.

[36] See footnote 33.

BACT Performance Testing

For Units 13, 14, 15, and 16, the permit requires an initial source test to ascertain initial compliance with the NO_X BACT limits. The permit allows the Permittee to test on only one of Unit 13 or 14 (which are identical make and model), and one of Unit 15 or 16 (if they are identical make and model – if not the same make, model, and engine configuration, the permit requires a source test on each unit), on the assumption that the units are similar.

No source testing is required for Unit 17.

4.7. Ambient Air Quality Requirements for NO_X, CO, SO_2, and PM-10

The City included ambient demonstrations for NO_X, CO (PSD requirements)[37]; and SO_2 and PM-10 (minor permit requirements). A memorandum describing the Department's review of the ambient demonstrations is in Appendix B of this TAR.

A summary of the ambient air quality protection requirements listed in the memorandum is as follows:

Phase 1

(1) For Units 13, 14, and 17 (A, B and BS in the modeling memorandum), construct and maintain each exhaust stack to have a release point that is at least 26 meters above ground.

(2) Limit the maximum fuel sulfur content to 0.10 percent, by weight.

(3) For Unit 17, limit the operation to 500 hr/yr.

(4) For Units 8 and 9, limit the operation of each unit to 3,000 hr/yr.

(5) The emergency backup units (Units 1, 2, 3, 4, 5 and 6) may not be operated concurrently with the phase 1 primary units (Units 13, 14, 17, 8 and 9). An emergency backup unit may only be operated during periods where a primary unit of equal or greater capacity is not operating.

Phase 2

(1) For Units 15 and 16 (C and D in the modeling memorandum), construct and maintain each exhaust stack to have a release point that is at least 26 meters above ground.

(2) Remove Units 1 through 9 upon startup of Units 15 or 16 (whichever unit is started up first).

(3) For Units 13, 14, and 17, limit the maximum fuel sulfur content to 0.10 percent, by weight.

(4) For Units 15 and 16, limit the maximum fuel sulfur content to 15 parts per million (ppm), by weight.

(5) For Units 15 and 16, limit the maximum NO_X emission rate to 16 lbs/hr.

(6) For Units 13 and 14, limit the combined output to 73.04 GW-hr/yr

[37] The City revised their application during the public comment period to avoid PSD for CO. The ambient assessment is no longer necessary as a PSD requirement, but it still valid as the emission rates used in the assessment are conservative.

(7) For Units 15 and 16, limit the combined output to 36.52 GW-hr/yr.

(8) For Unit 17, limit the operation to 500 hr/yr.

Phase 1, Items 2 through 4 and phase 2, Items 2 through 8 are also avoidance limits, described in other sections of this TAR.

4.8. New Source Performance Standards

Units 15 and 16 are subject to New Source Performance Standards (NSPS) Subpart IIII for stationary compression ignition (CI) internal combustion engines (ICE). As described in 40 C.F.R. 60.4200(a)(2), these provisions apply to owners and operators of stationary CI ICE that commence construction[38] after July 11, 2005 where the stationary CI ICE are manufactured after April 1, 2006 and are not fire pump engines, or modify or reconstruct their stationary CI ICE after July 11, 2005.

The City ordered Units 13 and 14 in 2005,[39] so they are pre-2007 model year engines. Units 13 and 14 have an engine displacement greater than 30 liters per cylinder. Therefore, Units 13 and 14 are not subject to 40 C.F.R. 60, Subpart IIII.

The City did not specify the cylinder displacement of Units 15 and 16 in the application. For the phase 2 engines, the City assumed in the application the same emission factors as for the phase 1 Wärtsilä 12V32C engines, which have a displacement greater than 30 liters per cylinder. The City also assumed the Wärtsilä 12V32C engines for the compliance demonstrations. If the City elects to install an engine with less than 30 liters per cylinder, they must submit a permit application.

Units 15 and 16 are non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder. An owner or operator must:

(1) reduce the NO_X emissions by 90 percent or more, or limit the NO_X to 1.6 g/kW-hr; and

(2) reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI ICE exhaust to 0.15 g/kW-hr.

The NSPS Subpart IIII requirements associated with the engines are in the permit as required under 40 C.F.R. 52.21(r)(3) and 18 AAC 50.306(d). In addition, the permit refers to Table 8 of Subpart IIII. This table specifies the provisions of Subpart A that are applicable to the Permittee.

4.9. Equipment Maintenance

As described in 18 AAC 50.544(c)(3), the permit must include maintenance of equipment according to the manufacturer's or operator's maintenance procedures. The Department has included maintenance requirements in the permit.

[38] For the purpose of Subpart IIII, the date that construction *commences* is the date the engine is ordered by the owner or operator.

[39] Phone conversation with Al Bohn, HMH, June 7, 2006.

5. Stationary Source-Wide Requirements

This section includes pollution prohibited requirements. These requirements are necessary to ensure that the project complies with the requirements of AS 46.14 and 18 AAC 50, as described in 18 AAC 50.544(b)(1).

6. General Source Testing Requirements

These requirements are necessary to ensure that the project complies with the requirements of AS 46.14 and 18 AAC 50, as described in 18 AAC 50.544(b)(1) and 18 AAC 50.306(d)(1).

7. Recordkeeping, Reporting, and Certification Requirements

All air quality control permits must contain procedures for recordkeeping, reporting, and certification.

Information request and certification requirements are specifically required under 18 AAC 50.200 and 18 AAC 50.205, respectively.

8. Terms to Make Permit Enforceable

The permit contains additional requirements as necessary to ensure that a Permittee will construct and operate the stationary source or modification in accordance with 18 AAC 50, as described in 18 AAC 50.544(i).

9. Permit Administration

The DHPP is currently operating under Operating Permit No. 215TVP01, Revision 1. The Department is in the process of issuing renewal Operating Permit No. AQ0215TVP02.

At the time of the preliminary decision for Permit No. AQ0215CPT02, the City has **not** requested that the Department incorporate the provisions of this construction permit into the operating permit.

The City may proceed with **construction** of the project authorized in Permit No. AQ0215CPT02 upon permit issuance. However, because the provisions in Permit No. AQ0215CPT02 are Title 1 modifications, federal law prohibits the City from **operating** under the construction permit provisions until the Department has issued (1) a revision to Permit No. 215TVP01, Revision 1[40] that contains the provisions of the construction permit; or (2) the department has issued an operating permit renewal that includes the construction permit provisions.

[40] More specifically, the City may operate under the provisions of the construction permit after EPA approves of the Title V operating permit revision containing the construction permit provisions, or 45 days after the Department submits the revision to EPA for approval, whichever comes first (unless EPA disapproves of the Project).

Appendix A

Emission Factors

Table A-1 – Emission Calculation Data

Unit No.	Rating KW-E	Fuel Rate @ 100% Load	Phase 1	Phase 2	Emission Factors			
					NO_X	PM-10	CO	VOC
1	300	23.2 gal/hr	150,000 kW-hr/yr	n/a	9.1 g/kW-hr	0.0573 lb/mmBtu	0.85 lb/mmBtu	0.09 lb/mmBtu
		Application	11,600 gal/yr	n/a	Manuf. Data, Permit No. 9625-AA003	AP-42 Table 3.4-2, 10/96 for total PM-10	AP-42 Table 3.4-1, 10/96	AP-42 Table 3.4-1, 10/96
2	300	23.2 gal/hr	150,000 kW-hr/yr	n/a	9.1 g/kW-hr	0.0573 lb/mmBtu	0.85 lb/mmBtu	0.09 lb/mmBtu
		Application	11,600 gal/yr	n/a	Manuf. Data, Permit No. 9625-AA003	AP-42 Table 3.4-2, 10/96 for total PM-10	AP-42 Table 3.4-1, 10/96	AP-42 Table 3.4-1, 10/96
3	600	46.1	300,000 kW-hr/yr	n/a	10.2 g/kW-hr	0.0573 lb/mmBtu	0.85 lb/mmBtu	0.09 lb/mmBtu
		Application	23,050 gal/yr	n/a	Manuf. Data, Permit No. 9625-AA003	AP-42 Table 3.4-2, 10/96 for total PM-10	AP-42 Table 3.4-1, 10/96	AP-42 Table 3.4-1, 10/96
4	830	60.4	415,000 kW-hr/yr	n/a	17.6 g/kW-hr	0.0573 lb/mmBtu	0.85 lb/mmBtu	0.09 lb/mmBtu
		Application	30,200 gal/yr	n/a	Manuf. Data, Permit No. 9625-AA003	AP-42 Table 3.4-2, 10/96 for total PM-10	AP-42 Table 3.4-1, 10/96	AP-42 Table 3.4-1, 10/96
5	620	44.2	310,000 kW-hr/yr	n/a	18.8 g/kW-hr	0.0573 lb/mmBtu	0.85 lb/mmBtu	0.09 lb/mmBtu
		Application	22,100 gal/yr	n/a	Manuf. Data, Permit No. 9625-AA003	AP-42 Table 3.4-2, 10/96 for total PM-10	AP-42 Table 3.4-1, 10/96	AP-42 Table 3.4-1, 10/96
6	1,440	103.0	720,000 kW-hr/yr	n/a	14.6 g/kW-hr	0.0573 lb/mmBtu	0.85 lb/mmBtu	0.09 lb/mmBtu
		Application	51,500 gal/yr	n/a	Manuf. Data, Permit No. 9625-AA003	AP-42 Table 3.4-2, 10/96 for total PM-10	AP-42 Table 3.4-1, 10/96	AP-42 Table 3.4-1, 10/96

Unit No.	Rating KW-E	Fuel Rate @ 100% Load	Phase 1	Phase 2	Emission Factors			
					NO_X	PM-10	CO	VOC
7	1,180	77.0	3,540,000 kW-hr/yr	n/a	**17.7 g/kW-hr**	0.0573 lb/mmBtu	0.85 lb/mmBtu	0.09 lb/mmBtu
		Application	231,000 gal/yr	n/a	Manuf. Data, Permit No. 9625-AA003[b]	AP-42 Table 3.4-2, 10/96 for total PM-10	AP-42 Table 3.4-1, 10/96	AP-42 Table 3.4-1, 10/96
8	1,230	86.6	3,690,000 kW-hr/yr	n/a	8.7 g/kW-hr	0.0573 lb/mmBtu	0.85 lb/mmBtu	0.09 lb/mmBtu
		Application	259,800 gal/yr	n/a	Manuf. Data, Permit No. 9625-AA003[b]	AP-42 Table 3.4-2, 10/96 for total PM-10	AP-42 Table 3.4-1, 10/96	AP-42 Table 3.4-1, 10/96
13	5,211	313.8	45,648,36 0 kW-hr/yr	**73,040,000 kW-hr/yr** **2,199,110 gal/yr**	**13.6 g/kW-hr**	**0.187 g/kW-hr**	11.3 lb/hr	0.09 lb/mmBtu
		Manuf. Data, applic.	2,748,888 gal/yr		Manuf. Data, App D of 11/10 applic.	Manuf. Data, App D of 11/10 applic.	Manuf. Data, applic supplement 12/7/2006.	AP-42 Table 3.4-1, 10/96
14	5,211	313.8	45,648,36 0 kW-hr/yr		**13.6 g/kW-hr**	**0.187 g/kW-hr**	11.3 lb/hr	0.09 lb/mmBtu
		Manuf. Data, applic.	2,748,888 gal/yr		Manuf. Data, App D of 11/10 applic.	Manuf. Data, App D of 11/10 applic.	Manuf. Data, applic supplement 12/7/2006	AP-42 Table 3.4-1, 10/96
15	5,211	313.8	n/a	**36,520,000 kW-hr/yr** **1,099,555 gal/yr**	**1.36 g/kW-hr**	**0.075 g/kW-hr**	11.3 lb/hr	0.09 lb/mmBtu
		Manuf. Data, applic.	n/a		Manuf. Data App D of 11/10 reduced by 90%	Manuf. Data App D of 11/10 reduced by 60%	Manuf. Data, applic supplement 12/7/2006	AP-42 Table 3.4-1, 10/96
16	5,211	313.8	n/a		**1.36 g/kW-hr**	**0.075 g/kW-hr**	11.3 lb/hr	0.09 lb/mmBtu
		Manuf. Data, applic.	n/a		Manuf. Data App D of 11/10 reduced by 90%	Manuf. Data App D of 11/10 reduced by 60%	Manuf. Data, applic supplement 12/7/2006	AP-42 Table 3.4-1, 10/96

Unit No.	Rating KW-E	Fuel Rate @ 100% Load	Phase 1	Phase 2	Emission Factors			
					NO_X	PM-10	CO	VOC
17	250	19	125,000 kW-hr/yr	125,000 kW-hr/yr	**5.75 g/kW-hr**	1.27 g/kW-hr	4.43 g/kW-hr (at 25% load)	3.27 g/kW-hr
		Manuf. Data, applic. supplement	9,500 gal/yr	9,500 gal/yr	Manuf. Data, applic. Supplement 10/30/06	Manuf. Data, applic. Supplement, 10/30/06	Manuf. Data, applic. Supplement, 10/30/06	Manuf. Data, applic. Supplement, 10/30/06

Table Notes:
[a] Emission Factors assumed to be at 100 percent load unless otherwise noted.
[b] The Department notes that the NO_X emission factor for Unit 7 is a BACT limit. Operating Permit No. 215TVP01 Revision 1 does not mention that this is a BACT limit.

Appendix B

Modeling Review Memorandum

MEMORANDUM

State of Alaska

Department of Environmental Conservation
Division of Air Quality

TO: File

DATE: October 9, 2006

FILE NO: AQ0215CPT02 - Modeling

PHONE NO: 465-5100

THRU:

FROM: Alan Schuler, P.E.
Environmental Engineer
Air Permits Program

SUBJECT: Review of DHPP Ambient Assessments

This memorandum summarizes the Department's findings regarding the ambient assessments submitted by the City of Unalaska (the City) for the Dutch Harbor Power Plant (DHPP). The City submitted this analysis in support of their November 2005 Prevention of Significant Deterioration (PSD) permit application. The Department finds that the City's application and supplemental information adequately complies with the source impact analysis required under 40 CFR 52.21(k), the pre-construction monitoring analysis required under 40 CFR 52.21(m)(1), and the additional impact analysis required under 40 CFR 52.21(o). The City's ambient air analysis adequately demonstrates that operating the DHPP emission units within the requested constraints will not cause or contribute to a violation of the Alaska Ambient Air Quality Standards (AAAQS) provided in 18 AAC 50.010, or the maximum allowable increases (increments) listed in 18 AAC 50.020.

BACKGROUND

Project Location and Area Classification

The city of Unalaska is located on the north side of Unalaska Island, which is part of the Aleutian Islands chain. Dutch Harbor is a neighborhood of the city, located on Amaknak Island, and is connected by bridge to Unalaska Island. The entire area is unclassified in regards to compliance with the AAAQS. For purposes of increment compliance, Unalaska is a Class II area of the South Central Alaska Intrastate Air Quality Control Region. The nearest Class I area, Simeonof National Wildlife Refuge, is located three hundred miles east-northeast from Dutch Harbor.

Source/Project Description

The DHPP is an existing PSD-major stationary source operating under the Title V permit, 215TVP01. The Title V permit incorporated the terms and conditions of the previous PSD permit, 9625-AA003, issued on June 21, 1996.

The existing combustion units consist of eight diesel-fired generator sets. The City is planning to replace the existing units with four 5 megawatt (MW) diesel-fired generators and a 250 kilowatt (kW) black-start generator. The new units will be located in a new power house, which will be built adjacent to the existing power house.

The project will occur in two phases. In Phase 1, the City will install two 5 MW Wartsila generators and the new black-start unit. The City will also operate two existing generators in a limited capacity mode, and relegate the other six existing generators to an emergency stand-by status. During Phase 2, the City will install two more 5 MW generators and retire all existing units.

Ambient Demonstration Requirements

The increase in emissions classifies both phases of the project as a PSD-major modification for oxides of nitrogen (NOx) and carbon monoxide (CO). Per 18 AAC 50.306, PSD applicants must essentially comply with the federal PSD requirements in 40 CFR 52.21. The ambient requirements include:

- A "Source Impact Analysis" (aka an ambient AAAQS and increment analysis) for the PSD-triggered pollutants – per 40 CFR 52.21(k),
- An "Air Quality Analysis" (aka preconstruction monitoring data) for the PSD-triggered pollutants – per 40 CFR 52.21(m);
- An "Additional Impact Analyses" – per 40 CFR 52.21(o); and
- A Class I impact analysis (for sources which may affect a Class I area) – per 40 CFR 52.21(p).

The nearest Class I area is too distant to warrant a Class I impact analysis. However, the City is subject to the remaining requirements in regards to in regards to their nitrogen dioxide (NO_2) and CO impacts.

The project also requires a minor air quality control permit under the following provisions:

- 18 AAC 50.502(c)(2)(B) – installation of an emission unit with a rated capacity of 10 million Btu (MMBtu) or more per hour in a sulfur dioxide (SO_2) special protection area (both phases);
- 18 AAC 50.502(c)(3) – increase in particulate matter (PM-10) emissions of at least 10 tons per year (tpy) each (Phase 1); and
- 18 AAC 50.508(6) – revisions to an existing Title I permit condition.

Applicants subject to 18 AAC 50.502(c)(2)(B) must provide an ambient SO_2 AAAQS analysis per 18 AAC 50.540(c)(2)(C). Applicants subject to 18 AAC 50.502(c)(3) must provide an ambient AAAQS analysis for the triggered pollutants per 18 AAC 50.540(c)(2)(A). Therefore, the City was required to provide an ambient SO_2 and PM-10 AAAQS analysis to satisfy these conditions.

Applicants subject to 18 AAC 50.508(6) must show the effect of revising or revoking the permit term or condition per 18 AAC 50.540(k)(3). The existing permit contains provisions to protect the SO_2 and PM-10 increment. Therefore, the Department also asked the City to provide an updated SO_2 and PM-10 increment analysis.

Project Submittals
HMH Consulting, LLC (HMH) prepared the PSD application and conducted the ambient NO_2, SO_2, PM-10 and CO assessment on behalf of the City. The City submitted the application on November 14, 2005. However, the City did not provide the permit application fees needed in order for the Department to start its review until January 5, 2006. The Department deemed the application incomplete on March 2, 2006. The City provided their response, which included a revised ambient assessment, on May 15, 2006. HMH provided additional modeling files regarding "flagpole" receptors via electronic mail (e-mail) on May 19, 2006 and May 22, 2006. The City provided revised PM-10 emission estimates and changed their Owner Requested Limit (ORL) for Phase 2 on September 15, 2006.

AMBIENT AIR POLLUTANT DATA

40 CFR 52.21(m)(1) requires PSD applicants to submit ambient air monitoring data describing the air quality in the vicinity of the project, unless the existing concentration or the project impact is less than the monitoring threshold provided in 40 CFR 52.21(i)(5). The requirement only pertains to the pollutants subject to PSD review. If monitoring is required, the data are to be collected prior to construction. Hence, these data are referred as "pre-construction monitoring" data. Ambient "background" data may also be needed to supplement the ambient assessment of the proposed project. The City's approach for meeting both data needs is discussed below.

Pre-Construction Monitoring
The City used computer analysis (modeling) to demonstrate that the NO_2 and CO project impacts are less than the pre-construction monitoring thresholds. The City used the data and methodology discussed in the *Source Impact Analysis* section of this memorandum.

The City provided the project impacts from both phases of the project. However, the Department only evaluated the Phase 2 impacts since this reflects the impact from all of the new emission units.[41, 42] As shown in Table 1, the maximum NO_2 and CO impacts are less than the pre-construction monitoring thresholds. Therefore, pre-construction monitoring is not required.

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[41] The City could have, but did not, subtract the contribution from the removed units in the Phase 2 project impact analysis. Therefore, the City's assessment of the Phase 2 project impacts is conservative.

[42] The project impacts provided in the application indicates the Phase 1 impacts are greater than the Phase 2 impacts. This is due to the City's inclusion of the impacts from the existing units that will continue to operate during Phase 1. While this approach is appropriate for determining the impact from the entire stationary source (see *Source Impact Analysis* discussion), it overstates the impacts due to just the modification. The City nevertheless took this approach to reduce the number of runs (which was already quite numerous).

Table 1: Pre-Construction Monitoring Assessment[43]

Air Pollutant	Avg. Period	Phase 2 Project Impact ($\mu g/m^3$)	Monitoring Threshold ($\mu g/m^3$)
NO_2	Annual	**10**	14
CO	8-hour	**490**	575

Background Concentrations
In addition to the pre-construction monitoring requirements for PSD pollutants, ambient "background" data may also be needed to supplement the ambient impact analysis. The background concentration represents impacts from sources not included in the modeling analysis. Typical examples include natural, area-wide, and long-range transport sources. The background concentration must be evaluated on a case-by-case basis for each ambient analysis. Once the background concentration is determined, it is added to the modeled concentration to estimate the total ambient concentration. Hence, background concentrations are typically needed for all air pollutants included in an AAAQS compliance demonstration, regardless of whether or not PSD pre-construction monitoring is required.

The Department provided recommended background values while reviewing the modeling protocol. While not stated as such in our reply, the Department recommended using the same SO_2 and PM-10 values as used by the City in their 1995 PSD application. These values have also been used by other local sources: UniSea (1997 and 2002) and Westward Seafoods (2004). Since there is no local SO_2 or PM-10 ambient data, applicants in Unalaska have used data from another remote area (Healy: 1990-1991 data) to represent the expected local background concentration. These values continue to be acceptable, especially since the SO_2 and PM-10 emissions in Dutch Harbor are increment limited rather than the AAAQS limited.

For the NO_2 background concentration, the Department recommended using the monitoring data jointly collected by the City and UniSea between May 1997 and April 1998. This NO_2 monitoring station was sited to measure the local maximum NO_2 concentration. While this data includes impacts from modeled sources, it also includes impacts from non-modeled sources. Therefore, it is the best available data set for representing the local NO_2 background concentration.

The City used the Department's recommended NO_2, SO_2 and PM-10 values in their application. The values are provided in the *Results and Discussion* subsection of this memorandum. The City did not need to obtain a CO background concentration since the project impacts are less than the significant impact level (SIL) – see *Results and Discussion* subsection.

[43] All concentrations are reported in micrograms per cubic meter ($\mu g/m^3$).

SOURCE IMPACT ANALYSIS

The City used modeling to predict the ambient NO_2, SO_2, PM-10 and CO air quality impacts. The Department's findings regarding the City's analysis are provided below.

Approach

The City submitted a modeling protocol on February 18, 2004. Several sets of comments and responses ensued over the next several months. The Department approved the protocol, as clarified/revised by the City, on October 12, 2004.

The City used a multi-step approach for modeling each project phase. The City first conducted a project impact analysis (referred as a "Stage 1" analysis in the application) to determine if the impacts from the DHPP emission units (new and existing) exceed the SIL.[44] The City conducted a project impact analysis for each pollutant/averaging period, and each meteorological data year.

For those pollutants/averaging periods with significant impacts, the City would next include the off-site sources and conduct a cumulative impact analysis (referred as a "Stage 2" analysis in the application). However, the City would first reduce the receptor grid for that pollutant/averaging period to just those receptors where the DHPP had significant impacts. The City reduced the grid by importing the receptor coordinates and project impacts into a spreadsheet and culling those receptors with insignificant impacts. The resulting grid contained only those receptors where the impact was significant during any of the five meteorological data years (for the given pollutant and averaging period). This approach is more refined than the more typical approach of using a generic "significant impact" grid for all pollutants, but it helped reduce the lengthy run-time and made the assessment more manageable.

For purposes of demonstrating compliance with the increment, the City initially compared the maximum impacts from the AAAQS analysis to the Class II increments. This is a conservative method for demonstrating compliance with the increment since the AAAQS impact will always be equal to, or greater than, the increment impact. However, if the AAAQS impact exceeded the Class II increment, then the City would rerun the increment analysis with just the units that consume/expand the increment.

In the Phase 1 analysis, the City found a limited number of modeled violations of the short-term SO_2 increment at two receptors. The City reran the analysis for just the receptors and days with modeled violations, and showed that the DHPP impacts are less than the significant impact level (SIL) during the periods of concern. The Department reviewed this supplemental SO_2 analysis and made several additional runs to confirm the City's conclusions. The numerical results are provided later in this memorandum. The City did not need to conduct a supplemental increment analysis for Phase 2 or any other pollutant in Phase 1.

Model Selection

There are a number of air dispersion models available to applicants and regulators. The U.S. Environmental Protection Agency (EPA) lists these models in their *Guideline on Air Quality*

[44] As previously noted, the City did not subtract the impact from the emission units that will be removed in Phase 2.

Models (Guideline). The City used EPA's *AERMOD Modeling System* (AERMOD) for the ambient analysis. AERMOD is an appropriate model for this analysis.

The AERMOD Modeling System consists of three components: AERMAP (which is used to process terrain data and develop elevations for the receptor grid), AERMET (which is used to process the meteorological data), and AERMOD (which is used to estimate the ambient concentrations). The City used the current version for AERMET and AERMOD (version 04300). The City used the version of AERMAP available at the time they processed the terrain data (version 03107).

EPA listed the AERMOD Modeling System as a Guideline method on November 9, 2005. However, the Department has not yet updated our adoption by reference of the Guideline. Therefore, AERMOD is still a non-Guideline model under state regulation.

Applicants using non-Guideline models must obtain case-by-case approval from the Commissioner per 18 AAC 50.215(c)(3). The Commissioner delegated the responsibility for approving non-Guideline methods to Tom Chapple (Director, Air Division) on February 23, 2006. The Director approved the use of AERMOD for the DHPP PSD application on February 28, 2006.

Use of a non-Guideline model is also subject to public comment. Therefore, the Department is seeking public comment regarding the use of AERMOD in the public notice regarding the preliminary permit decision.

Meteorological Data
AERMOD requires hourly meteorological data to estimate plume dispersion. According to the Guideline, five years of adequately representative data should be used (when available) to account for year-to-year variation.

The City used five years (1995-1999) of surface data collected by the National Weather Service (NWS) at the Dutch Harbor Airport. The NWS station is located approximately 400 meters from the DHPP. The City also used concurrent upper air data from the nearest available source, the NWS station in Cold Bay.

AERMET requires site-specific values (representative of the meteorological site) for the following three surface characteristics: noon-time albedo, bowen ratio, and surface roughness length. The City used the values proposed and approved in their modeling protocol. The City segregated the surrounding area into four sectors to reflect the two main types of surface conditions: grassland and ocean. The City assigned the values by month in order to adjust the surface characteristics according to season. The values selected by the City are repeated in Table 8-3 of their November 2005 application.

EPA allows applicants to compare the high second-high (h2h) modeled concentration to the short-term air quality standards if at least one year of temporally representative site-specific, or five years of representative off-site data, are used. When these criteria are not met, then applicants must use the high first-high (h1h) concentration. In all cases, applicants must compare the h1h modeled concentration to the annual average standards/increments, the SILs, and the pre-construction monitoring thresholds.

The City could have compared the h2h impacts to the short-term standards/increments since they used five years of NWS data. However, they instead took the conservative approach of using the h1h impact.

Emission Unit Inventory
The DHPP emission unit inventory is provided in Table 2. The Phase 1 project impact analysis consisted of Units A, B, BS, 8, and 9.[45] The City did not model the other existing units since they will be relegated to emergency standby status and therefore, not operated concurrently with the new units. The Department did not make the City include an alternative scenario for the emergency standby units since the City already demonstrated compliance for these units in support of the 1996 PSD permit. The Phase 2 project impact inventory consisted of Units A – D and BS.

Table 2: DHPP Emission Unit Inventory

Unit ID	Description	Rating
New Emission Units		
A	Wartsila 12V32C	5,211 kW
B	Wartsila 12V32C	5,211 kW
C	Similar to A and B	5,211 kW
D	Similar to A and B	5,211 kW
BS	Cat C-9 Black-Start	250 kW
Existing Emission Units		
8	Caterpillar 3516	1,180 kW
9	Caterpillar 3512B	1,230 kW

Emission Rates and Stack Parameters
The assumed emission rates and stack parameters have significant roles in an ambient demonstration. Therefore, the Department checks these parameters very carefully.

Load Analysis
The maximum ambient concentration does not always occur during the full-load conditions that typically produce the maximum emissions. The relatively poor dispersion that occurs with cooler exhaust temperatures and slower part-load exit velocities may produce the maximum ambient impacts. Therefore, EPA recommends that part-load conditions be analyzed as well as full-load conditions.

[45] The unit numbers in permit 215TVP01 do not match the unit numbers used by the City and listed in the previous PSD permit, 9625-AA003. The Department is using the City's numbers in this memorandum. The City's Unit 8 is Unit 7 in 215TVP01. The City's Unit 9 is Unit 8 in 215TVP01.

The City used EPA's *SCREEN3* dispersion model to conduct a load analysis of a Wartsila unit. The City limited the load analysis to the PSD-triggered pollutants, NO_2 and CO. They compared the results between the 100 percent, 75 percent and 50 percent loads, and found that the 100 percent load scenario produced the largest ambient impact. The City therefore used the 100 percent load scenario in all of their ambient assessments.

Stack Heights

Stack height can be a critical component of an ambient demonstration, especially when an emission unit is subject to downwash. Therefore, including minimum stack height requirements in the permit is sometimes warranted, which is the case here.

The City assumed a 26-meter stack height for all new emission units. The Department is including this 26-meter assumption as a permit condition.

Horizontal/Capped Stacks

The presence of non-vertical stacks or stacks with rain caps requires special handling in an AERMOD analysis. All of the DHPP emission units have vertical stacks without raincaps. All of the off-site emission units within the DHPP significant impact area also have vertical stacks without raincaps. However, some of the off-site sources located beyond the significant impact area have horizontal/capped stacks. With Department approval, the City used UniSea's past characterization for these stacks.[46] The Department did not re-evaluate how these stacks should be characterized due to their relatively small size and the lack of current stack information for these units.[47]

Annual Limits

The modeled annual emission rates reflect the ORLs provided in the City's May 15th response. These ORLs are listed below:

Phase 1 Annual Limits:
- Units A and B – no annual restrictions.
- Unit BS – 500 hours per year (hr/yr)
- Units 8 and 9 – 3,000 hr/yr (each)

Phase 2 Annual Limits:
- Units A, B, C and D – combined limit of 109.56 gigawatt-hours per year (GW-hr/yr).[48]
- Unit BS – 500 hr/yr

[46] The City used UniSea's modeling files as the starting point for developing their off-site inventory. UniSea's 2003 analysis is the most recent, prior assessment for this area.

[47] Electronic mail (e-mail) message from Alan Schuler to Krista Thieman (HMH); *RE: DHPP Modeling*; March 29, 2006.

[48] The PSD application listed the Phase 2 ORL as 107.34 GW-hr/yr. However, the City used 109.56 GW-hr/yr in the modeling analysis.

The City revised the Phase 2 ORL for Units A – D on September 15th to the following:

- Units A and B – combined limit of 73.04 GW-hr/yr
- Units C and D – combined limit of 36.52 GW-hr/yr.

The City did not provide a reason for requesting the annual ORLs. However, it appears that the purpose is to protect the NO_2 AAAQS and increment. The Department is therefore including the ORLs as ambient air conditions.

The City did not provide an updated NO_2 analysis for the revised Phase 2 ORL for Units A - D. They stated the analysis for the 109.56 GW-hr/yr ORL was adequate.

The Department reran the NO_2 AAAQS analysis for the worst-case met year (1996) using the revised ORL to make sure the previous submittal was adequate. The maximum NO_2 impact is identical to the City's value. Therefore, the City's submittal is still acceptable.

Ambient SO_2 Modeling

SO_2 emissions are directly related to the amount of sulfur in the fuel. The current limit in 215TVP01 is 0.17 percent, by weight. The City is asking for a new ORL of 0.10 percent for all Phase 1 operations. The City used the 0.10 percent assumption in their Phase 1 modeling analysis. In Phase 2, the City assumed the two additional 5 MW generators (Units C and D) will burn fuel containing 0.0015 percent (15 ppm) sulfur, per a proposed New Source Performance Standard (NSPS) that was pending at the time. The City assumed the other two 5 MW generators (Units A and B), and the black-start unit, are continuing to burn fuel containing 0.10 percent sulfur. The Department is including these fuel sulfur assumptions as ambient air requirements due to their critical influence in the ambient SO_2 analysis.

Phase 1 NOx Emissions

The City used the full-load vendor data to characterize the NOx emissions from Units A and B. The NOx emission rate is 156 pounds per hour (lb/hr), or 19.7 grams per second (g/s). This value represents the NOx emissions with fuel injection timing retard (FITR), which is an integral component of the proposed Wartsila engines. The City assumed Units A and B have *no* post-combustion controls.

Phase 2 NOx Emissions

The City assumed the NSPS would require a 90-percent reduction in diesel engine NOx emissions. Therefore, they reduced the assumed NOx emission rate for Units C and D by 90 percent. The resulting NOx emission rate is 15.6 lb/hr. The Department is imposing this assumption as a permit limit in order to protect the NO_2 AAAQS and increment.[49]

Ambient NO_2 Modeling

The modeling of ambient NO_2 concentrations can sometimes be refined through the use of ambient air data or assumptions. The City used the *Plume Volume Molar Ratio Method*

[49] The NOx emission rate limit may be rounded up to 16 lb/hr without jeopardizing the City's compliance demonstration.

(PVMRM) to refine the estimated ambient NO_2 concentrations. The use of this method is appropriate, but warrants discussion.

EPA and Department Approval
PVMRM is non-Guideline method and therefore, requires EPA and Department approval per 18 AAC 50.215(c)(3). EPA Region 10 (R10) granted the City permission to use PVMRM for the DHPP PSD application on March 24, 2006.[50] Mary Stovall, acting on behalf of the Air Director, approved the use of PVMRM for the DHPP PSD application on June 13, 2006.

Public Comment
As previously noted, use of a non-Guideline model is subject to public comment. Therefore, the Department is seeking public comment regarding the use of PVMRM in the public notice for the preliminary permit decision.

In-Stack NO_2-to-NOx Ratio
The NOx emissions created during combustion is partly nitric oxide (NO) and partly NO_2. EPA's long-standing practice is to assume that 90 percent (by volume) of the in-stack emissions is NO, and 10 percent is NO_2. After the combustion gas exits the stack, additional NO_2 is created as the exhaust mixes with atmospheric ozone.

Applicants may either use this default 10 percent NO_2-to-NOx in-stack ratio, or assign alternative in-stack NO_2/NOx ratios. The City used the default assumption. The use of a 10 percent NO_2-to-NOx in-stack ratio is appropriate.

Ozone Data
PVMRM is essentially an improved version of the *Ozone Limiting Method* (OLM), which is a Guideline NO_2 modeling method. Both methods require ambient ozone data in order to determine how much of the NO is converted to NO_2.

The City used the same Unalaska ozone data as used by UniSea in their 1996 PSD ambient analysis using OLM. The City and UniSea jointly collected the ozone data from June 15, 1995 through May 13, 1996 in a remote valley located 4 miles from Dutch Harbor. They also monitored for NOx to determine and correct the ozone concentrations during the occasional periods of NOx scavenging. The ozone data was reviewed and approved by the Department's monitoring group in the late 1990's. UniSea filled the missing data, which includes the full month period between May 14th and June 14th, with the worst-case ozone concentrations measured during a five-year period at Denali National Park. UniSea demonstrated that the Denali data is a conservative substitute.

The Department provided HMH an electronic copy of UniSea's ozone data file. The data are non-concurrent with most of the City's five years of meteorological data, but they are still acceptable for this analysis. UniSea included the hourly ozone concentrations with a 1992 site-specific meteorological data file. UniSea included ozone concentrations for the leap-year day

[50] E-mail message from Herman Wong (R10) to Alan Schuler; *RE: PVMRM Request – DHPP*; March 24, 2006.

(February 29th), but did not include values for the resulting 366th day of the year (December 31, 1992). Therefore, the City needed to fill-in the missing ozone concentrations for December 31st. The City assumed the hourly concentrations on December 31st are 40 parts per billion (ppb).

The Department subsequently retrieved the original quarterly monitoring report (which UniSea submitted in support of their 1996 PSD application), and found that the mean concentration for December 31st is 33 ppb. Therefore, the City's use of 40 ppb is conservative. The Department has since provided HMH with the hourly values for December 31st so that they can use the actual values in future submittals.

NO_2 Increment Modeling

The use of PVMRM requires special care when modeling the NO_2 increment. Due to the ozone limiting feature of the algorithm, the NOx emissions that occur during different time periods must be modeled separately.

The City was able to demonstrate compliance with the NO_2 increment without subtracting the DHPP portion of the baseline NO_2 concentration. This approach is conservative and precluded the need for making separate baseline runs.

In regards to the off-site inventory, the City essentially used the modeling files generated in 2002 by UniSea. This is the latest available inventory for Unalaska. However, UniSea used the Ambient Ratio Method (ARM) for refining the ambient NO_2 concentration, which does not require the same level of care as needed for PVMRM. UniSea was therefore able to model the *change* in emissions rather than modeling the full baseline inventory.

HMH had several discussions with the Department to determine how best to proceed when using PVMRM. While not standard practice, the Department allowed the City to use UniSea's change in emissions for the off-site inventory.[51] The Department allowed the City to use this non-standard practice due to the City's conservative approach for modeling the DHPP increment impacts and the lack of adjacent off-site sources.

Ambient Air Boundary

For purposes of air quality modeling, "ambient air" means outside air to which the public has access. Ambient air typically excludes that portion of the atmosphere within a stationary source's boundary.

[51] The Department developed the baseline inventories for Unalaska in the early 1990's. Since then, a number of errors have been found. However, since applicants were modeling the *change* in emissions rather than the actual *baseline* concentration, the corrections were only applied to the change in emissions contained in the modeling files. The underlying baseline spreadsheets were never corrected. Therefore, there is no consolidated and accurate information available regarding the baseline inventories. Due to this deficiency in the baseline spreadsheets, the best available information was the existing ISC modeling files, which for many local sources, only contains the change in emissions. The Department has started the lengthy process of going back through the historic permit actions to compile the various error discoveries and correct the baseline inventories, so that the corrections will be available for future applicants.

The City plans to install a fence around the perimeter of the DHPP after they finish constructing the new power house. The City therefore could have used the fence-line as the ambient air boundary. However, the City took the conservative approach of using the exterior walls as the ambient air boundary.

Receptor Grid

The ground-level receptor grids are discussed in detail in the City's May 15, 2006 response. In general, the SIL grid consisted of receptors placed every 25 meters within 500-meters of the DHPP and along the south of face of Amaknak Mountain. The rest of the grid consisted of receptors placed every 150 meters, out to 3500-meters from the DHPP. As previously noted, the City limited the cumulative impact runs to those receptors with significant impacts. However, the City also added 25-meter grids as needed to ensure the maximum impact was found. The Department accepts the City's ground-level receptor grids.

Per the Department's request, the City included "flagpole" receptors at the Mark Air apartment buildings, which is located just uphill of the DHPP. The City set the flagpole elevations equal to the height of the second floor. The Department is providing these results separately from the ground-level impacts. Per EPA policy, flagpole receptors are subject to ambient air quality standards, but not increments.[52]

Downwash

Downwash refers to conditions where nearby structures influence plume dispersion. Downwash can occur when a stack height is less than a height derived by a procedure called "Good Engineering Practice," as defined in 18 AAC 50.990(42). The modeling of downwash-related impacts requires the inclusion of dimensions from nearby buildings.

EPA has established specific algorithms for determining which buildings must be included in the analysis and for determining the profile dimensions that would influence the plume from a given stack. EPA has incorporated these algorithms into the following computer programs "Building Profile Input Program" (BPIP), and "Building Profile Input Program for PRIME" (BPIPPRM). The City used BPIPPRM (version 04274) to determine the building profiles needed by AERMOD. This is the appropriate building profile program for AERMOD.

The City inadvertently used slightly different base elevations between the DHPP stacks and the power house buildings. The maximum variation is 3 meters. However, the Department reran BPIPPRM with consistent base elevations and found that in this case, the City's error did not affect the resulting downwash characteristics. Therefore, the City's BPIPPRM analysis is acceptable.

Off-Site Impacts

In a cumulative impact analysis, the applicant must include impacts from large sources located within 50 km of the applicant's significant impact area. These impacts from "off-site" sources are typically assessed through modeling.

[52] EPA Memorandum, *Applicability of PSD Increments to Building Rooftops*, Joseph Cannon (Air and Radiation Assistant Administrator) to Charles Jeter (EPA Region IV Administrator), June 11, 1984.

The City essentially used the same off-site inventory as used by UniSea in their 2002 ambient assessment. However, they did make several minor changes, which they described in Section 5 of their May 15, 2006 response. The changes are reasonable and acceptable.

Results and Discussion

The maximum DHPP NO_2, SO_2, PM-10 and CO impacts for both phases is shown Table 3, along with the SIL. The maximum CO impacts for both phases are less than the SIL. The maximum project impacts for the other pollutants exceed the SIL. Therefore, the City was required to assess the cumulative NO_2, SO_2 and PM-10 impacts.

Table 3: Maximum DHPP Impacts (Phase 1 and 2)

Air Pollutant	Avg. Period	Max Phase 1 Impact ($\mu g/m^3$)	Max Phase 2 Impact ($\mu g/m^3$)	SIL ($\mu g/m^3$)
NO_2	Annual	15	10	**1.0**
PM-10	24-hr	23	26	**5**
	Annual	2	2	**1.0**
SO_2	3-hr	68	64	**25**
	24-hr	39	38	**5**
	Annual	4	4	**1.0**
CO	1-hr	939	1,339	**2,000**
	8-hr	330	490	**500**

The maximum NO_2, SO_2 and PM-10 ambient standard impacts at ground-level receptors are shown in Tables 4 and 5. The maximum ambient standard impacts at the flagpole receptors are shown in Tables 6 and 7. The background concentrations, total impacts and AAAQS are also shown. Tables 4 and 6 provide the Phase 1 results. Tables 5 and 7 provide the Phase 2 results. All of the total impacts are less than the AAAQS.

Table 4: Maximum Phase 1 AAAQS Impacts at Ground-level Receptors

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Bkgd Conc ($\mu g/m^3$)	TOTAL IMPACT: Max conc plus bkgd ($\mu g/m^3$)	Ambient Standard ($\mu g/m^3$)
NO_2	Annual	52.6	18.6	**71**	100
PM-10	24-hour	24.8	31	**56**	150
	Annual	2.8	5	**8**	50
SO_2	3-hr	579	44	**623**	1300
	24-hr	173	26	**199**	365
	Annual	6.4	5	**11**	80

Table 5: Maximum Phase 2 AAAQS Impacts at Ground-level Receptors

Air Pollutant	Avg. Period	Maximum Modeled Conc. (μg/m³)	Bkgd Conc (μg/m³)	TOTAL IMPACT: Max conc plus bkgd (μg/m³)	Ambient Standard (μg/m³)
NO_2	Annual	52.3	18.6	**71**	100
PM-10	24-hour	26.3	31	**57**	150
	Annual	2.0	5	**7**	50
SO_2	3-hr	260	44	**304**	1300
	24-hr	53.5	26	**80**	365
	Annual	4.3	5	**9**	80

Table 6: Maximum Phase 1 AAAQS Impacts at Flagpole Receptors (Mark Air Apartments)

Air Pollutant	Avg. Period	Maximum Modeled Conc. (μg/m³)	Bkgd Conc (μg/m³)	TOTAL IMPACT: Max conc plus bkgd (μg/m³)	Ambient Standard (μg/m³)
NO_2	Annual	10	18.6	**29**	100
PM-10	24-hour	11	31	**42**	150
	Annual	1	5	**6**	50
SO_2	3-hr	56	44	**100**	1300
	24-hr	18	26	**44**	365
	Annual	3	5	**8**	80

Table 7: Maximum Phase 2 AAAQS Impacts at Flagpole Receptors (Mark Air Apartments)

Air Pollutant	Avg. Period	Maximum Modeled Conc. (μg/m³)	Bkgd Conc (μg/m³)	TOTAL IMPACT: Max conc plus bkgd (μg/m³)	Ambient Standard (μg/m³)
NO_2	Annual	9	18.6	**28**	100
PM-10	24-hour	17	31	**48**	150
	Annual	1	5	**6**	50
SO_2	3-hr	61	44	**105**	1300
	24-hr	21	26	**47**	365
	Annual	3	5	**8**	80

The maximum NO_2, SO_2 and PM-10 increment impacts are shown in Tables 8 and 9, along with the Class II increments. The Phase 1 impacts are shown in Table 8. The Phase 2 impacts are shown in Table 9. Most of the maximum impacts are less than the applicable Class II increments. The short-term SO_2 impacts in Phase 1 are the only exception.

The Department notes that the h2h 3-hour SO_2 impact in Phase 1 is 429 $\mu g/m^3$, which is less than the 512 $\mu g/m^3$ Class II increment. Therefore, the City could have demonstrated compliance with the 3-hour SO_2 increment if they had used the h2h concentration instead of the h1h concentration.

Table 8: Maximum Phase 1 Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Class II Increment Standard ($\mu g/m^3$)
NO_2	Annual	**16.9**	25
PM-10	24-hour	**24.8** [1]	30
	Annual	**2.8** [1]	17
SO_2	3-hr	**579**	512
	24-hr	**151**	91
	Annual	**6.4** [1]	20

[1] Value from AAAQS analysis.

Table 9: Maximum Phase 2 Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Class II Increment Standard ($\mu g/m^3$)
NO_2	Annual	**16.9**	25
PM-10	24-hour	**26.3**	30
	Annual	**2.0** [1]	17
SO_2	3-hr	**260**	512
	24-hr	**53.5** [1]	91
	Annual	**4.3** [1]	20

[1] Value from AAAQS analysis.

The City addressed the SO_2 exceedances by comparing the DHPP concentration during the time and location of concern to the SIL. The maximum DHPP impacts during the time/locations of concern are provided in Table 7-2 of the City's May 15, 2006 response. In summary, the largest 3-hour DHPP impact is 2 $\mu g/m^3$, which is well below the 25 $\mu g/m^3$ SIL. The largest 24-hour DHPP impact is 0.31 $\mu g/m^3$, which is well below the 5 $\mu g/m^3$ SIL. Therefore, the City has demonstrated that they are not causing or contributing to the modeled violations.

The Department notes that the modeled increment violations occur near off-site sources and are likely due to the off-site source's own emissions. Impacts within a source's ambient air boundary caused from their own emission units are not considered as ambient air impacts and therefore, do not need to be compared to the AAAQS and increments. Therefore, a closer review of these off-site sources would likely show that the potential violations are due to the conservative manner in which these sources were modeled. The Department has found in past Unalaska assessments that there are no modeled violations when using a more accurate approach.

It is important to note that since ambient concentrations vary with distance from each emission unit, the maximum values shown represent the highest value that may occur within the area. The concentrations at other locations would be less than the reported values.

ADDITIONAL IMPACT ANALYSES

Per 40 CFR 52.21(o), PSD applicants must assess the impact from the proposed project and associated growth on visibility, soils, and vegetation. The City provided the soil and vegetation analysis in Section 10 of their application and the visibility analysis in Part 7 of their May 15, 2006 response. The Department's findings are provided below.

Visibility Impacts

PSD applicants must assess whether the emissions from their stationary source, including associated growth, will impair visibility. Visibility impairment means any humanly perceptible change in visibility (visual range, contrast, or coloration) from that which would have existed under natural conditions. Visibility impacts can be in the form of visible plumes ("plume blight") or in a general, area-wide reduction in visibility ("regional haze").

Alaska does not have plume blight standards. For Class I areas, the Federal Land Manager provides the desired thresholds. There are no established thresholds for Class II areas.

The nearest Class I area, the Simeonof Wilderness Area, is located 480 km from Unalaska. This is well beyond the range of a typical plume blight analysis. The Department nevertheless asked the City to conduct a plume blight analysis since it is a required element of a PSD application. The Department asked the City to conduct the analysis as if the Class I area was located within the typical range of a plume blight analysis (50 km). If the plume blight analysis shows no impacts at 50 km, then there will be no impacts at a further distance.

The City used VISCREEN (version 1.01) to estimate the worst-case plume blight. This is an appropriate model for conducting a cursory plume blight analysis. They appropriately assumed an ozone concentration of 40 parts per billion (ppb). They also assumed a "background visual range" of 150 km. The City's assumption is more conservative than the 250 km value used in their 1995 PSD application and by other Unalaska applicants. However, it's an acceptable value and may be more representative of a maritime background visual range than the previously accepted value. The City's analysis shows that there are no visibility impacts within the Class I area.[53]

Soil Impacts
There is little information available regarding the effects of air pollutants on local soils. The Department is therefore using the AAAQS assessment as a surrogate measure. Since the City demonstrated compliance with the AAAQS, the Department concludes that the DHPP project will not cause adverse soil impacts.

Vegetation Impacts
The City stated the DHPP project will not cause adverse vegetation impacts for the following reasons:

- the ambient NO_2 and SO_2 concentrations are less than the screening thresholds listed in EPA's *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA 450/2-81-078);
- the ambient concentrations are less than the NO_2 and SO_2 NAAQS; and
- the ambient SO_2 concentrations are less than "the levels needed to have a direct affect on lichen."

EPA's screening thresholds and the maximum cumulative NO_2 and SO_2 impacts (from either phase) are shown in Table 10. All of the impacts are less than EPA's thresholds.

Table 10: Comparison to EPA's Vegetation Sensitivity Thresholds

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Worst-case Sensitivity Threshold ($\mu g/m^3$)
NO_2	Annual	**71**	94
SO_2	3-hr	**623**	786
	Annual	**11**	18

Lichens are more sensitive to air pollutants than vascular plants since they lack roots and derive all growth requirements from the atmosphere. Some lichen species are adversely affected when the annual average SO_2 concentration ranges between 13 to 26 $\mu g/m^3$.[54] While it is not known whether lichens in Unalaska have this same sensitivity, these values provide a surrogate measure of the potential sensitivity threshold. The maximum cumulative annual average SO_2 impact in Unalaska is 11 $\mu g/m^3$, which is less than the 13 $\mu g/m^3$ sensitivity threshold reported for some lichens. Therefore, no adverse impacts are expected.

[53] The City's VISCREEN analysis shows the potential for visibility impacts if an observer is looking "outside" of the Class I area. However, this test only applies to "Integral Vistas." Alaska only has two Integral Vistas, both of which are associated with the Denali National Park Class I area. Since Simeonof does not have any Integral Vistas, the Integral Vista test is not applicable.

[54] Air Quality Monitoring on the Tongass National Forest (USDA – Forest Service; September 1994).

Secondary Impacts
40 CFR 52.21(o)(2) requires PSD applicants to assess the impacts from general commercial, residential, industrial and other growth associated with the source or modification. The City assessed the potential for growth during both the construction and operation phases. The City does not expect any significant increases in secondary impacts. The City's assessment is reasonable.

CONCLUSION

The Department reviewed the City's ambient assessment for the DHPP and concluded the following:

1. The City's application and supplemental information adequately complies with the source impact analysis required under 40 CFR 52.21(k) ***Source Impact Analysis***. The City has adequately demonstrated that the NO_2, SO_2, PM-10 and CO emissions associated with operating the stationary source within the requested operating limits will not cause or contribute to a violation of the AAAQS provided in 18 AAC 50.010 or the maximum allowable increases (increments), as applicable, provided in 18 AAC 50.020.

2. The City appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.

3. The City adequately complies with the pre-application air quality analysis required under 40 CFR 52.21(m)(1) ***Preapplication Analysis***.

4. The City's application adequately complies with the additional visibility, soils, vegetation and secondary impact analysis required under 40 CFR 52.21(o) ***Additional Impact Analysis***.

The Department developed conditions in the air quality control construction permit to ensure the City complies with the ambient air quality standards and increments. These conditions are summarized below.

<u>Phase 1</u>

1. For Units A, B and BS, construct and maintain each exhaust stack to have a release point that is at least 26 meters above ground.
2. Limit the maximum fuel sulfur content to 0.10 percent, by weight.
3. For Unit BS, limit the operation to 500 hr/yr.
4. For Units 8 and 9, limit the operation of each unit to 3,000 hr/yr.
5. The emergency backup units (Units 1, 2, 3, 4, 5 and 6) may not be operated concurrently with the Phase 1 primary units (Units A, B, BS, 8 and 9). An emergency backup unit may only be operated during periods where a primary unit of equal or greater capacity is not operating.

Phase 2

1. For Units C and D, construct and maintain each exhaust stack to have a release point that is at least 26 meters above ground.
2. Remove Units 1 – 9 upon acceptance of Unit C or D (whichever unit is accepted first).
3. For Units A, B and BS, limit the maximum fuel sulfur content to 0.10 percent, by weight.
4. For Units C and D, limit the maximum fuel sulfur content to 15 parts per million (ppm), by weight.
5. For Units C and D, limit the maximum NOx emission rate to 16 lbs/hr.
6. For Units A and B, limit the combined output to 73.04 GW-hr/yr
7. For Units C and D, limit the combined output to 36.52 GW-hr/yr.
8. For Unit BS, limit the operation to 500 hr/yr.

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Response to Comments on Preliminary Construction Permit No. AQ0215CPT02
City of Unalaska
Dutch Harbor Power Plant – Renovation Project

Prepared by Sally A. Ryan January 31, 2007

This document provides the Alaska Department of Environmental Conservation's (Department's) reply to all public comments on the preliminary decision to issue Construction Permit No. AQ0215CPT02 to the City of Unalaska, for the Power Plant Renovation Project. The Department provided opportunity for public comment on the permit starting November 29, 2006 and ending December 29, 2006.

The comments are shown below in Arial font. The Department's responses are shown in *Times New Roman italic font.*

Commenter: City of Unalaska

1. "The draft CP [Construction Permit No. AQ0215CPT02] contains terms and conditions specific to the construction of the power plant in addition to some of the existing Title V operating permit conditions and of course extraneous conditions also. ADEC (the Department) did not incorporate all applicable operating conditions into the draft CP. Conditions that satisfy regulatory requirements for operation under this construction permit have been specifically excluded. Consequently, as documented on both the Construction Permit cover page and on page 32 of the TAR under Section 9 Permit Administration *'The Permittee shall **not operate** the emission units authorized in this permit until after the Department issues a revised operating permit that includes the provision of this construction permit. The Permittee **may begin actual construction** of the emission units authorized in this permit upon permit issuance."* The reason for this stipulation is most likely because the City did not apply for an administrative revision incorporating the construction permit into the existing operating permit (See following paragraph [comment #2]). Therefore, for permit clarity, the City requests that the permit conditions specifically related to operating, in addition to those noted on the attached table, be removed from this construction permit (i.e. if the plant is not operating, these conditions are not applicable).

   "Since construction takes time, the City felt it is in their best interests to pursue a construction permit, then, at the appropriate time, submit administrative revision documents and fees to the Department. As noted, the construction permit includes terms and conditions for operation, excluding some monitoring, recordkeeping, and reporting requirements, and then details that the facility cannot operate under this construction permit. Operating restrictions of the current Title V operating permit have been included in the TAR, when in reality; the construction permit application contains new 'ORLs' applicable to the power plant project."

<u>Background</u>: For the state emission standards, the Department has made a distinction between "initial" and "on-going" monitoring, recordkeeping, and reporting (mr&r). Initial mr&r is the

mr&r required to support the initial compliance demonstrations (or performance tests). On-going mr&r is the mr&r to show continued compliance with the state emission standards. The Department ***must*** *establish* ***initial*** *mr&r in the Title I permit (unless the Department is satisfied that the source does not need a performance test). The Department* ***may*** *establish* ***on-going*** *mr&r in the Title I permit (unless the Department is conducting an integrated review[1] of the Title V permit revision, in which case it* ***must*** *establish* ***on-going*** *mr&r in the Title 1 permit.)*

In the DHPP preliminary permit, the Department included ***initial*** *mr&r for the state emission standards as necessary (i.e. if the permit included a performance test requirement). The Department, at its discretion, did not include* ***on-going*** *mr&r for state emission standards in the preliminary permit. (The Department could not have left this out had this been an integrated review.) The Department can easily establish this mr&r in the Title V permit or permit revision, using standard permit conditions. The Department has clarified Section 4.4 of the TAR to indicate that the permit does not contain mr&r needed* ***specifically*** *for a Title V operating permit or under the Compliance Assurance Monitoring rule.*

On the other hand, the Department established in the preliminary permit ***initial*** *as well as* ***on-going*** *mr&r for all Title I provisions (i.e. PSD avoidance and ambient air quality protection requirements established by this permit.) There are no standard conditions for on-going compliance with these provisions. It is appropriate for the Department to establish this mr&r in the construction permit and not wait for the operating permit revision.*

<u>*Response:*</u> *The Department did not remove* "permit conditions specifically related to operating, in addition to those noted on the attached table"[2] *as follows:*

(1) *The Department has authority to establish initial and on-going mr&r for all requirements (state emissions standards as well as Title I provisions) under 18 AAC 50.306(d) and 18 AAC 50.544(c)(1);*

(2) *The Department is not* ***required*** *to establish on-going mr&r for the state emission standards in the construction permit;*

(3) *The Permittee requested that the Department* ***not*** *conduct an "integrated" review of the construction permit and an operating permit revision;*

(4) *The Permittee must wait for an operating permit amendment before operating because this is a Title 1 modification to the operating permit.[3]*

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1 For a Title V source that is planning a modification that requires a Title I permit as well as an operating permit modification (such as DHPP), the Permittee may request under 18 AAC 50.326(c)(1) an "integrated" review of the Title I and Title V permits. Under this regulation, the Department can consolidate all required public notices, hearings, and comment periods.

2 *The commenter is not specific as to which conditions they mean by* "permit conditions specifically related to operating, in addition to those noted on the attached table." *The Department has provided specific responses to each comment in the table attached to the comments below.*

3 40 C.F.R. 71.6(a)(13)(i) allows the [Title V] permittee to make Section 502(b)(10) changes without a permit revision if the changes are not Title I modification, *and the changes do not exceed* emissions *allowable under the permit (whether expressed therein as a rate of emissions or in terms of total emissions).* For the purpose of changes to Title V permits, lacking EPA guidance to the contrary, the Department considers Title I modifications to be PSD major modifications, and modifications under New Source Performance Standards or under Section 112. Therefore, this is a Title I modification for this purpose.

2. The Department includes a great deal of calculations with 0.17 wt%S or fuel limits that are not applicable as the City used 0.10 wt%S in the Phase 1. Revised ORLs have been included in the construction permit application. Any evaluation referencing or including the existing Title V Permit is not justified. This section should be deleted from the TAR, and the City should not be charged for this Department expense. It is clearly evident that the plant will not operate under this scenario. The analysis detailed in Table 9 and 10 of the TAR is not applicable since the City will utilize 0.10 wt%S, therefore, these tables need to be deleted.

Response: *The application does not specifically state whether the Owner Requested Limits (ORLs) are for ambient air quality protection or for PSD avoidance. The Department generally assumes that all ORLs are needed for ambient air quality protection, if they were assumed in the ambient demonstration (for any modeled pollutant). This is because it is difficult to predict modeling results conclusively without actually doing the modeling analysis, especially if ambient concentrations are close to a given standard. However, we can more easily determine if an ORL is necessary for permit applicability avoidance just by calculating what emissions would have been without the limit.*

*In developing Tables 8 through 10, the Department intended to clarify the purpose of the ORLS for future reference, in case an applicant requests a change to a limit. In the tables, the Department showed what the emissions would have been for the project (1) with **just** the new fuel sulfur limit **of 0.10 wt%S** (Table 8) and (2) with **just** the new operating hour limits (Tables 9 and 10). The Department has corrected and clarified the tables to better present its intention.*

For this project, the applicant requested a fuel sulfur limit of 0.10 wt%S and various annual operating hour limits for specific units. These "new" ORLs replaced existing limits in the Title V permit (0.17 wt%S and fuel quantity limits listed in Permit No. 215TVP01, Revision 1, Table 2).[4] *(The Department understands that after the new permit is issued, the plant will use 0.10 wt%S, **not** 0.17 wt%S.)*

*Tables 1 and 4 of the preliminary TAR show that, with **all** of the "new" ORLs (i.e. the new operating hour limits **and** the new fuel sulfur limit), neither phase of the project is PSD for SO_2, PM or VOC.*

*Table 8 – Existing Units 1 – 8: TVP Rev 1 Table 2 fuel quantity limits, new Units 13 – 18: no operating hour limits. Fuel sulfur **0.10 wt%S** for all units. The results show that the **operating hour** limits are necessary for SO_2 and PM-10 modification avoidance for phase 1 PSD Avoidance, and for SO_2, PM-10, and VOC PSD modification avoidance for phase 2.*

*Table 9 – Phase 1 new operational limits (Units 1 – 6: 500 hpy each, Units 7 & 8: 3,000 hpy each, Unit 17: 500 hpy, and Units 15 & 16: not operated). Fuel sulfur **0.17 wt% S** for all units. The results show that the **fuel sulfur** limit of 0.10 wt%S is necessary for phase 1 SO_2 PSD modification avoidance (fuel sulfur does not change results for PM-10 and VOC).*

[4] The Department considers the base case to be as calculated using previous permit limits listed in the Title V permit. The Department did not rescind these previous provisions with Permit No. AQ0215CPT02, so they stay in effect until the new limits go into effect.

*Table 10 – Phase 2 new operational limits (Units 1 – 8: retired, Units 13 & 14: 75.04 GW-hr/yr combined, Units 15 & 16: 36.56 GW-hr/yr, and Unit 17: 500 hpy). Fuel sulfur **0.17 wt% S** for all units. The results show that the **fuel sulfur** limit is necessary for Phase 2 SO_2 PSD modification avoidance (fuel sulfur does not change results for PM-10 and VOC).*

The conclusions from the tables support Findings #8 through #10 in the TAR. The Department will not remove the tables.

3. The Department states that under the original application an "owner requested limits" (ORL) was requested under 18 AAC 50.508(5), noting the correct citations should be 18 AAC 50.225. The repetition of this comment under the Department findings: comment 8, 9, 10, and 11 is unnecessary. The City requests the correction be noted once in the TAR and once in the ORL.

<u>Response</u>: *The Department states in the preliminary TAR that* "The application indicates that the City requests these ORLs under 18 AAC 50.225. These are not ORLs under 18 AAC 50.225, because the purpose of a limit under 18 AAC 50.225 is to avoid a permit altogether."

The statements in Findings #8 through #10 indicating the regulatory basis of the ORLS (as supported by Tables 8 through 10) are for completeness and for future reference, not to differentiate from and ORL under 18 AAC 50.225, so the Department will leave these in.

The Department will remove one of the footnotes, as only one is necessary.

4. There are several conditions in the construction permit related to the New Source Performance Standards Subpart IIII that are applicable to smaller engines in power production and/or cylinder size. However, the TAR (page 31) specifically indicates that the Department assumed the Phase 2 engines would be similar to the Phase 1 engines, specifically referencing a cylinder size larger than 30 liter per cylinder. Furthermore, the Department noted that if this assumption is not correct, the Department needs to be notified and then they will include NSPS requirements for engines smaller than30 liters per cylinder. If these seven conditions are included in the construction permit then revise the assumptions in the TAR to reflect the possibility of these engines and include the provisions for smaller engines.

<u>Response</u>: *The preliminary TAR stated* "If there is a possibility that the City may choose a smaller cylinder size, the Department requests that the City include this in their comments on the preliminary permit. The Department will then include the NSPS requirements for engines smaller than 30 liters per cylinder." *The Departments intention was to provide flexibility for the City to install the smaller cylinder size engines, it that were still a possibility. However, this affects more than just NSPS requirements. The City's emission calculations and compliance demonstrations assumed the phase 2 engines were equivalent to the 12 cylinder Wärtsilä 12V32C engine. Further the BACT assessment did not reflect the different NSPS that would be the BACT floor for the engines, if they were less than 30 liters per cylinder. Therefore, the option of installing engines with less than 30 liters per cylinder is not available under this permit. Therefore, the Department will not include the NSPS for the smaller engines, and will correct the permit as necessary.*

5. This Construction Permit is incomplete based on the PSD permit requirements of 50.306(d)(1).

   Throughout the Construction Permit and TAR, the CO emission rates need to be updated for EU 13 and 14 based on 11.3 lb/hr and the applicability of a PSD and/or minor permit evaluated. The calculated CO tons/year for both phases of the project are below the applicability limits for PSD and a minor permit.

Response: The Department revised CO emission rates based on information provided by the applicant on December 7, 2006.

6. The AP-42 PM-10 emission factor of 0.0496 lb/MMBtu is correct and has been correctly applied throughout the application. The State of Alaska does not require back-half (condensable) analysis in Method 5 source test when demonstrating compliance. Consequently, it is not the AP-42 "total PM 10" that is used in calculations. The City has already addressed this issue with Department staff. Each entry in the TAR indicating there has been an error regarding the correct AP-42 emission factor needs to be removed. Additionally, Table A-1 needs to be corrected in accordance with the application value of 0.0496 lb/MMBtu.

Response: Permit applicability requirements in 18 AAC 50.502 and 18 AAC 50.306 (which refers to Federal Regulations in 40 C.F.R. 52.21 refer to "PM-10". In addition, ambient air quality requirements in 18 AAC 50.215 refers to "PM-10". These regulations do not specify that "PM-10" means "filterable" PM-10 only. Further, in 18 AAC 50.220(c)(1)(F) the Department indicates that the "reference test method" for PM-10 must follow procedures set out in Appendix M of 40 C.F.R. 51. 40 C.F.R. 51 Appendix M contains Methods 201, 201A and 202. Method 201 applies to "in-stack" measurement of PM-10. Section 1.1 of the method states "The EPA recognizes that condensable emissions not collected by an in-stack method are also PM-10, and that emissions that contribute to ambient PM-10 levels are the sum of condensable emissions and emissions measured by an in-stack PM-10 method, such as this method or Method 201A. Therefore, for establishing source contributions to ambient levels of PM-10, such as for emission inventory purposes, EPA suggests that source PM-10 measurement include both in-stack PM-10 and condensable emissions. Condensable [e]missions may be measured by an impinger analysis in combination with this method." Method 202 applies to the determination of condensable particulate matter (CPM) emissions from stationary sources.

Therefore the argument that "The State of Alaska does not require back-half (condensable) analysis in Method 5 source test when demonstrating compliance" does not apply for permit applicability or ambient air quality determinations. The Department does not require Method 5 source tests to determine PM-10 emissions.

However, the SIP standard in 18 AC 50.055(b) refers to "particulate matter". In 18 AAC 50.220(c)(1)(E) the Department indicates that the "reference test method" for "particulate matter" must follow procedures set out in Appendix A of 40 C.F.R. 60. Appendix A of 40 C.F.R. 60 Appendix A includes Method 5. Section 1.0 of Method 5 says "Particulate matter is withdrawn isokinetically from the source and collected on a glass filter. . ." The *standard condition for particulate matter source testing to show compliance with the PM SIP standard references 18 AAC 50.220. Because the SIP standard is for particulate matter (not PM-10) this means 18 AAC 50.220(c)(1)(E), which includes Method 5. The Department agrees with the commenter regarding the meaning of particulate matter emissions for the SIP standard.*

The Department clarified in footnote 15 in Section 4.4 of the preliminary TAR that for the SIP standard, it is appropriate to assume that PM means filterable PM. No other changes to TAR necessary.

7. On page 23 of the TAR, it looks like the Department is requiring the City to build the powerhouse to accommodate Phase 2 SCRs. Since the City has stated in their permit application they will comply with the applicable standards, the Department cannot mandate that the City construct the Phase 2 portion of the plant to include SCRs. The City has the option to choose an engine and BACT that complies with the applicable standards and permit and can be constructed under Phase 1 requirements.

<u>Response</u>: *-This permit does require an emission control technology "equivalent" to SCR for both BACT and to satisfy NSPS requirements for the phase 2 engines. If the City wishes to install smaller engines for phase 2 without a control technology equivalent to SCR, they must first submit a new permit application (and new permit) that authorizes a different BACT level of control. The Department has clarified the TAR to indicate that the Department is not mandating SCR to control NO_X to 90 percent. The intention of the paragraph on page 23 is to indicate that the costs for the emissions controls needed to comply with NSPS should be assigned to phase 2, for the NO_X BACT assessment.*

Condition	Description	Regulation	Typical CP	Typical OP or Existing TV OP Condition Number	Comment	*Department Response*
1	Authorization	40CFR52.21(r)(2)	X			*No response required.*
	Table 1, note a: "the listed....				References that these units have specific R&R. TAR indicated not MR&R included	*Permit not changed. TAR clarified to indicate that the Department did not include on-going mr&r for the state emissions standards in the permit. (The Department will add necessary on-going mr&r for state standards in operating permit revision. The Department included in the permit initial and on-going mr&r for the Title I provisions, as well as initial mr&r for the state standards as necessary.)*
2	Unit Information		X			*No response required.*
3	Labeling Requirements		X			*No response required.*
4	Nomenclature		X			*No response required.*
5	Stack Requirements		X			*No response required.*
6	Assessable Emissions (Annual Fees)	50.410	X	X	50.306(d)(2) requires inclusion of fees consistent with 50.400-.420	*No response required.*
7	Assessable Emission Estimate	50.410	X	X	Same as above	*No response required.*
8	Visible Emissions	18AAC50.055(a)(1)	X	X	Initial test within 30 day. Includes Monitoring and Reporting	*Permit not changed. The mr&r in the permit is for the initial compliance demonstration. (The Department will add necessary on-going mr&r in operating permit revision.) TAR revised for clarification.*
9	Particulate Matter	18AAC50.055(b)(1), 50.346(c)	X	X	Monitoring, Reporting & Recordkeeping?	*Permit not changed. The application included an initial compliance demonstration, so Department did not include an initial compliance demonstration, req't in the permit, hence no mr&r. (The Department will add necessary on-going mr&r in operating permit revision.) TAR revised for clarification.*

10	Sulfur Compound Emissions	18AAC50.0 55(c)	X	X	Monitoring, Reporting & Recordkeeping?	*Permit not changed. The Department has previously determined initial compliance with state sulfur compound standard based on fuel sulfur content. (The Department will add necessary on-going mr&r in operating permit revision.) TAR revised for clarification.*
	Owner requested Limits for PSD Avoidance				Department added ORL of 500 hours per EU 1-6; however, this is typical for emergency backup units.	*The application on page 1-A indicates that the City will place Units 1 – 6 in "emergency stand-by", which under EPA guidance is when "electric power from public utilities is unavailable" (or in this case, power from the primary units is unavailable). Preliminary permit condition 22c contains this req't and condition 22.1a and b contain corresponding mr&r. Therefore, it is not necessary for the Department to include the 500 hpy limit under PSD avoidance (although it is an appropriate assumption for PTE estimates.) Permit and TAR changed.*
11	Phase 1 Operational Limits to avoid PSD for SO2 and PM-10 EU 1-6 500 hrs EU 7-8 3000 hrs EU 17 500 hrs EU 15-16 no hours	50.508(5)	X	X	Add in CO reference.	*Permit revised as requested.*
12	Phase 1 Fuel Sulfur Content to avoid PSD for SO2	50.508(5)	X	X	0.10% by wt	*No response required.*
13	Phase 2 Operational Limits to avoid PSD for SO2, PM-10, and VOC. "Phase 2 commences... startup of Unit 15 or 16	50.508(5)	X	X	Add CO reference. Remove words commences and commencement. This wording is inconsistent with 40CFR52.21(b)(9). Reword to "Upon initial startup of either Unit 15 or 16, the Permittee....	*Added CO reference. Changed "commence" to "start" to define phase 1 and phase 2 of the Project. Did not change "commence" if the wording is from, or refers to, federal requirements.*
14	Phase 2 Fuel Sulfur Content to avoid PSD for SO2	50.508(5)	X	X	14.2(a) correct to Units 13, 14, or 17 (not 15)	*Permit changed as requested.*

15	NOx BACT Limit for Units 13 and 14		X	X		*No response required.*
16	NOx BACT Limit for Units 15 and 16		X	X		*No response required.*
17	**Remove.** CO BACT for Emission Units 13 and 14				Project is not PSD for CO. No longer applicable based on updated Wärtsilä guaranteed CO emissions rates.	*Permit changed in accordance with December 7, 2006 request to avoid PSD for CO.*
18	**Remove.** CO BACT for Emission Units 15 and 16				Project is not PSD for CO. No longer applicable based on updated Wärtsilä guaranteed CO emissions rates.	*Permit changed in accordance with December 7, 2006 request to avoid PSD for CO.*
19	**Remove.** CO BACT for Emission Unit 17				Project is not PSD for CO.	*Permit changed in accordance with December 7, 2006 request to avoid PSD for CO.*
20	Reassess NOx and CO BACT if P2 Commences more than 18 months				Remove CO. Definition of "commences" technically it has already commenced.	*Permit changed.*
21	Stack Configuration		X			*No response required.*

22	During P1 the permittee shall...comply with Condition 11 ("ORL") Condition 12 (PSD avoid for SO2 (0.10%)) Operational restriction detailing that EU ID 1-6 may operate only if one of the Phase 1 Primary Units are down. Monitor & Report Compliance (with condition 22.c) EER (for non-compliance with condition 22.c)		X	X	Numbering of sub-conditions. Delete Repetition of Condition 11 and Condition 12 Monitor and reporting requirements if operations do not comply with 22.c. Yes, appropriate to repeat for this section of the permit.	*The Department will retain the cross referencing of permit requirements. This practice clarifies the regulatory basis of a requirement and adds no burden to the Permittee.* *Mr&r for condition 22c is separate.*
23	After commencing Phase 2 the permittee shall: Condition 13, 14, and 16		X	X	References following condition 13 (operating limits), condition 14 (SO2 limits) and condition 16 (NOx BACT). Yes, appropriate to repeat for this section of the permit.	*No response required.*
	New Source Performance Standards, Subpart IIII				As amended July 2006. ***<u>Note:</u> Excluding obvious typos and changing "you" to "the Permittee (that owns and operates)", all the operating permit condition language in this section is verbatim to the cited regulation.***	*No response required.*
24	If displacement >30L, then Condition 25 and 26	40 C.F.R. 60.4204(c)	X	X		*No response required.*

25	Reduce NOx 90% or more or limit to 1.6 g/kW-hr	40 C.F.R. 60.4204(c)(1)	X	X		*No response required.*
26	Reduce PM10 10% or more or limit to 0.15 g/kW-hr	40 C.F.R. 60.4204(c)(2)	X	X		*No response required.*
27	Maintain engines according ....over life of engine.	40 C.F.R. 60.4206	X	X		*No response required.*
28	Oct. 1, 2007 Subpart IIII engine diesel requirements	40 C.F. R. 80.510(a), 40 C.F.R. 60.4207(a)	X	X		*No response required.*
29	Remove. Operate pre-2011 engine subject to Subpart IIII, can petition to use up "old fuel" inventory.	40 C.F.R. 60.4207(c)				*This condition provides for the Permittee to petition to the EPA administrator for approval to use fuel mixed with lubricating oil that do not meet NSPS fuel requirements. The Permittee did not provide any reason to delete it, and it is not otherwise inappropriate, therefore the Department will not remove.*
30	Pre-2011 engine subject to Subpart IIII, ... in areas not accessible by the Federal Aid Highway System may petition to mix fuel with used lubricating oil....	40 C.F.R. 60.4207(d)	X			*No response required.*
31	After Dec. 31, 2008, no installing engines that don't meet 2007 model year requirements.	40 C.F.R. 60.4208(a)	X			*No response required.*

32	**Remove.** See Comment	40 C.F.R. 60.4208(b)			Applicable to engines smaller than Phase 2 engines both in power production and/or cylinder size. The TAR (page 28) specifically indicates that the department assumed that engines with a cylinder size larger than 30 liter per cylinder and similar to the Wartsila will be selected for the Phase 2 engines. It is noted that if this assumption is not correct, the Department needs to be notified and then they will include NSPS requirements for engines smaller that 30 liters per cylinder.	*The option to add phase 2 engines with less than 30 liter displacement per cylinder was not addressed completely in the application. The Department has removed all references to NSPS req'ts for engines with a cylinder displacement less than 30 liters. If the City decides to add phase 2 engines with a cylinder displacement less than 30 liters per cylinder, the City must submit a new application. The application must include an approvable revised BACT assessment for the engines.*
33	**Remove.** See Comment	40 C.F.R. 60.4208(c)			Inapplicability same as previous comment.	*Agree - see previous response.*
34	**Remove.** See Comment	40 C.F.R. 60.4208(d)			Inapplicability same as previous comment.	*Agree - see previous response.*
35	**Remove.** See Comment	40 C.F.R. 60.4208(e)			Inapplicability same as previous comment.	*Agree - see previous response.*
36	**Remove.** See Comment	40 C.F.R. 60.4208(f)			Inapplicability same as previous comment.	*Agree - see previous response.*
37	**Remove.** See Comment	40 C.F.R. 60.4208(g)			Inapplicability same as previous comment.	*Agree - see previous response.*
38	**Remove.** See Comment	40 C.F.R. 60.4208(h)			Inapplicability same as previous comment.	*Agree - see previous response.*
39	Diesel PM filter used to comply with condition 25 and condition 26 need backpressure monitor....	40 C.F.R. 60.4209(b)	X		Remove reference to condition 25 (90%NOx reduction)	*Agree.*

40	Operate and maintain engines according to ...and meet requirements of 40 CFR 89, 94, and / or 1068, as applicable.	40 C.F.R. 60.4211(a)	X	X	Similar to condition 27, however, this is how the regulation is written.	*No response required.*
41	Condition 25 and 26 compliance demonstration.	40 C.F.R. 60.4211(d), (1), (2), and (3)	X	X		*No response required*
42	Performance Test Specifications	40 C.F.R. 60.4213, (a), (b, (c), (d), (e), (f)	X	X		*The Department changed "you" to [the Permittee].*
43	Performance Test Notification and Records	40 C.F.R. 60.421, (a)(1),(2)	X	X		*No response required*
44	Prior to Dec. 1, 2010....on Federal Highway Aid System not Accessible...refer to 40 CFR Part 69 for diesel fuel requirements...	40 C.F.R. 60.4216(a)	X	X		*No response required*
45	Governor of Alaska may submit....	40 C.F.R. 60.4216(b)			Extraneous.	*Agree, condition is not a direct requirement on the Permittee and any change in regulation does not apply as of the time of this permit. Condition deleted.*
46	Reference to Table 8 of Subpart IIII	40 C.F.R. 60.4218	X	X		*The Department changed "you" to [the Permittee].*
	Maintenance Requirements					*No response required.*

47	Maintenance - Units 13-18, perform regularly in accordance with ..., keep record, and have procedures onsite		X	X		*No response required.*
48	Air Pollution Prohibited	18AAC50.110, 18AAC346(a)	X	19	Standard Permit Condition II	*No response required.*
49	Requested Source Tests	18AAC50.345(k)	X	22		*No response required.*
50	Test Deadline Extension	18AAC50.345(l)	X	X		*No response required.*
51	Test Plans	18AAC50.345(m)	X	26		*No response required.*
52	Test Notification	18AAC50.345(n)	X	27		*No response required.*
53	Test Reports	18AAC50.345(o)		28		*No response required.*
54	Certification	18AAC50.345(j)	X	30		*No response required.*
55	Submittals		X	31		*No response required.*
56	Information Requests	18AAC50.345(i)	X	32		*No response required.*
57	Recordkeeping Requirements		X	33		*No response required.*
58	Excess Emission Reports	50.346(b)(2), SPC III		34 updated	50.346 Contains Title V standard permit conditions (SPC)	*No response required.*
59	Operating Reports	50.346(b)(6), SPC VII		35		*No response required.*
60		50.345(h)(1)-(4)	X	44		*No response required.*

61		50.345(c)(1), 50.345(c)(2)	X	38		*No response required.*
62		50.345(d)	X	39		*No response required.*
63		50.345(d)	X	40		*No response required.*
64		50.345(b)(1), 50.345(b)(2)	X	41		*No response required.*
65		50.345(f)	X	42		*No response required.*
66		50.345(g)	X	43		*No response required.*

Page	TAR Comment	Comment	***Department Response***
4		Last paragraph change reference to Unit 16 to 17	*TAR revised.*
5	2nd para - reference to Model Year 2010	This doesn't necessarily fit with the 18 month timeline	*Revised TAR and Table 1 of permit to indicate that they are post-2007 model year engines. This date is important for NSPS applicability.*
7	Table 1 - Phase 1 PSD Applicability Analysis	Recalculate CO emissions for EU 13 and 14 based on 11.3 lb/hr (49.5 tons/year/unit) totaling 139 tons/year. Consequently project falls below CO PSD Applicability Threshold and table should be updated.	*Table 1 of TAR revised in accordance with December 7, 2006 request to avoid PSD for CO.*
7	Table 1 - Phase 1 PSD Applicability Analysis	Recalculate PM10 emissions using the appropriate AP-42 emission factor of 0.0496 lb/MMBtu. State of Alaska does not include condensable PM. Revise Table 1 footnote.	*TAR not revised. See response to comment # 6 above.*
7, 8	Phase 1 needs a minor permit under 18 AAC 50.502(c)(2)(b) ...10 MMBtu/hr or more in SO2 special protection area....Table 2 assessed applicability 50.502(c)(3)...	Use correct AP42 PM10 emission factor (PM10 = 21 tons/year based on application restrictions) and update to include CO (135.2 - 117.1 = 18.1 tons/year change) with no minor permit. Revise Table 1 footnote.	*TAR not revised. See response to comment # 6.*
8	Table 2	Calculation of SO2 and PM10 emissions using a fuel wt of 0.17% is incorrect as defined in the City's permit application and elsewhere in the CP	*TAR revised as indicated in response to comment #2.*
9, 10	Tables 3 and 4	Update CO tons/year and correct reference to Table A-2 in Section 2.3.2	*CO emissions updated and corrected "Table A-2" to "Table A-1".*

11	Phase 2 needs a minor permit under 18 AAC 50.502(c)(2)(b) ...10 MMBtu/hr or more in SO2 special protection area....Table 2 assessed applicability under 50.502(c)(3)...	Use correct AP42 PM10 emission factor (PM10 = 21 tons/year based on application restrictions) and update to include CO with no minor permit. Revise Table 1 footnote.	*TAR not revised. See response to comment # 6 above.*
12	Comment (1)	Remove reference to CO as PSD.	*Finding#1 of TAR revised in accordance with December 7, 2006 request to avoid PSD for CO.*
12	Comments (3)	40 CFR 52.52?	*Corrected to 18 AAC 50.306 which refers to 40 C.F.R. 52.21.*
13	Comment (4) Table 7 - BACT Summary	Remove reference to SCR and remove CO BACT from the table entirely.	*NO_X BACT for the phase 2 engines is an emission control technology equivalent to SCR, so Department did not remove. CO BACT in Table 7 removed in accordance with December 7, 2006 request to avoid PSD for CO.*
13, 14	Comment (8) - For Phase 1, the revised application..... if these operational limits were not in place the ....PTE in table 1 would be higher...PSD for SO2, PM10, NOx etc .... Therefore, these limits.... under 18 AAC 50.508(5) for SO2 and PM-10 PSD avoidance.	Sentences 2-5 have no relevance in the context of this TAR. This TAR and associated construction permit should reflect the contents or operating parameters of the application. That is why the limit is requested so that the emission of these pollutants is less. Revise the last sentence of this comment to "These limits are "Owner Requested Limits under 18 AAC 50.508(5) for SO2, CO, and PM-10 PSD avoidance:	*Sentences 2-5 provide a context and reason for the ORLs. Department did not remove.* *Added "CO" to last sentence.*

14	Comment (9), (10)	Same comment as above. Relevance of the "if these operational limits were not in place" comments and calculations? This TAR should reflect the construction permit and information provided in the application. The application included an ORL for sulfur (under 50.508(5)). As stated in the TAR page 2 and throughout the CP and TAR, the City's power plant will utilize 0.10% wt sulfur fuel. Calculations with 0.17% wt sulfur and operating parameters are outside of the construction permit and should not be charge as a City expense.	*Please refer to previous response, TAR not changed.*
	Comment (11)	Same comment as above.	*Please refer to previous response, TAR not changed.*
	Comment (14) The City's application and subsequent submittals for a PSD construction permit application contained in 18AAC50.306 and 40 CFR 52.21. Comment (15) The City's application also included elements for a minor permit application listed 18 AAC 50.540.		*No response required.*
15	Particulate Matter	Correct reference to Wärtsilä engines from Units 13 through 16 to 13 and 14. Recalculated based on 10% excess air. Please provide documentation that 10% is typical for these engine size and manufacture.	*The burden is on the applicant to show what they assume is correct. Absent any documentation in the application that excess air is 15 percent, the Department assumed a more conservative, and more typical value for engines overall. Chris Whitney of Wärtsilä on January 18, 2007 confirmed that 10 percent oxygen is typical specifically for the Wärtsilä engine.*

15	4.5 PSD Avoidance	This paragraph contradicts other Department assumptions based on the fuel usage and operating restrictions of the units. And the existing fuel contract for the City.	*The first paragraph has no contradictions. The second paragraph provides context and reason for the ORLs. See response to comment #3.*
16	Sentence beginning "Appendix D of the original ....." and Footnote 15 - "Table 3.4-2...."	The AP-42 PM-10 emission factor of 0.0496 lb/MMBtu is correct and has been correctly applied throughout this application. The State of Alaska does not require back-half (condensable) analysis in Method 5 source test when demonstrating compliance. Consequently, it is not the AP-42 "total PM 10" that is used in calculations. This issue has previously been addressed with department staff (specifically regarding this project). Each entry in this TAR indicating there has been an error regarding the correct AP-42 emission factor needs to be removed.	*TAR not revised. See response to comment # 6.*
16-20	Section 4.5 PSD Avoidance calculated using "existing operating permit" parameters?	Revised ORLs have been included in the construction permit application. This section in general and any evaluation referencing or including "old" Title V Permit are not justified and Department costs should not be charged to the City. This section should be deleted.	*Section not deleted. See response to comment #3.*
	Table 8 - Relevance of PSD applicability analysis with "old" Title V Permit Limits.	It is evident that the plant will not operate under this scenario. Sentence or general text immediately after Table 8 "Therefore..."owner requested limits" under 18 AAC 50.508(5)..." has been repeated under Department findings comment 8, 9, 10, and 11.	*TAR not revised. See response to comment #3.*
19, 20	Table 9 and Table 10	These tables should be deleted The Department should not at the City's expense perform a calculation with anything other than the limits included in the City's application.	*See response to comment #3.*

23	Department Review of Phase 1 NOx BACT Assessment Therefore if the City wants the department to authorize engines that may be subject to Subpart IIII engines, they must build the powerhouse building must be built to accommodate SCR at this time. As such,...entire capitol cost of urea building and...expanded powerhouse to Phase 2.	. Remove this comment. Apply all associated Phase 2 SCR building costs to Phase 1 Since the City has stated in their permit application they will comply with the applicable standards, the Department cannot mandate that the City construct the Phase II portion of the plant to include SCRs. The City has the option to choose an engine and BACT that complies with the applicable standards and permit and can be constructed under Phase 1 requirements.	*The Department disagrees. The applicant requested authorization to install engines with greater than or equal to 30 liters per cylinder displacement. This will require a NO_X emission control technology equivalent to SCR. Therefore, all costs for the emission control technology should be assigned to phase 2.*

24	Table 12 – There is no list itemizing the costs that make up these O&M costs.....NJUS costs	Update O&M Costs to accurately reflect the Unalaska market. Comparison with the NJUS BACT analysis is interesting, but the Department's costs have not been updated for increased shipping and urea costs. Urea costs have increased dramatically since the NJUS permit application as well as shipping costs. In the Department's analysis of SCR operation, the Department's initial operating costs of $432,538/year were less than the material costs of Urea delivered to Unalaska ($660,441) without any labor or other costs. The City supplied a detailed analysis of these operating costs in a meeting with the Department on August 5, 2006. The Department has not requested or indicated that any additional information was required.	*In order to properly review the costs provided by the City, the Department needed an itemized list of O&M costs.*[5] *The Department back-calculated annual O&M costs shown in Attachment A, based on the City's annual O&M costs provided on page A-2 of the RIA dated 9/22/06. The Department divided the costs into labor and consumable cost in order to compare to a similar project, the NJUS power plant. Nome is also located in a remote area of Alaska, and could be considered even less accessible than the City of Unalaska. Nome has limited year-round access due to ice. On the other hand, the City may have more site constraints at the DHPP. However, because the City has access to excellent cargo line service and cargo dispatch facilities, the potential of year round availability of shipping services is greater and less storage is needed.* *The Department compared the City's cost estimates to the Department-approved costs for the NJUS project in order to construct a frame of reference for the costs provided by the City. This comparison showed the City's cost to be higher than the Department estimates for NJUS as indicated in Table 12 of the prelim. TAR. Because of the discrepancy, the SCR O&M costs provided by the City for the DHPP warranted more scrutiny by the Department. The Department could compare specific item costs to costs from other projects (such as Nome) or independent manufacturer estimates. Then we could make a decision on whether the difference was warranted* ***and why****.* *Because of their large contribution to the overall annual O&M costs, the Department focused attention on annual incremental service load, catalyst replacement, and normal maintenance.* *Notwithstanding the discussion above, although urea cost and urea shipping was a large contributor to the annual O&M cost, the Department was able to verify the accuracy of these estimates, and does not dispute them.*

5 *The Department did request for the City to prepare an itemized list such as this on 9/21/06, in response the City added Table 2 to the RIA.*

24	(1) Incremental Station Service Loads	The City disagrees with the Departments' statements. The building heating costs and energy costs were detailed to the Department. The calculations were based on the average annual heating index for Unalaska. The City disagrees with the Department's assertion that "it is only necessary to maintain the urea solution at only 50 degrees" The department has no operating basis for this statement other than an unsupported statement from the same personnel who estimated the total operating costs of the system is $200,000/ year less than the cost of the urea. The City personnel have over 20 years experience in the operation of urea systems in Alaska and the consequences of cold urea to piping systems. The average water temperature of the City's water supply is 40 degrees, the reverse osmosis system required for the urea solution has a recommended inlet water temperature of 60 degrees. According to Perry's Chemical Engineers' Handbook (7th Edition) by Robert H. Perry and Don W. Green; page 2-47 lists the solubility of Urea in water. The minimum temperature indicated is 17 degrees C (approximately 62 degrees F) for dissolving urea in water. The desired temperature of urea in solution is 70 degrees. The urea will have an average annual temperature of 46 degrees and since urea has a negative heat of solution index, additional heat is required to achieve the desired temperature as urea is added to the water. We have estimated based on the volume of urea and estimated annual ambient temperature, that the mixing solution must maintain at least 100 degrees F. Please provide technical documentation to support the Department's claim. The Department's question as to why there is an additional cost to heat the building can be answered as follows: the size of the building has increased extensively to accommodate the SCRs and a brand new mixing building was required..	*As shown in Attachment A, the City estimated $80,872 per year for incremental service loads. Table 2 of the RIA (see Attachment B) indicates building heat costs are $17,000 per year (for a 400 sf building), Process Heater 1 is $19,418 per year, and Process Heater 2 is $38,836 per year. According to a submittal prepared by EPS on 8/8/06 indicates Process Heater 1 heats urea sol'n to 100°F and Process Heater 2 keeps the urea sol'n at 100°F. The EPS submittal indicates that its estimates are engineers estimates based on Unalaska average annual heating degree days (and water temp as necessary) (calcs not included with original submittal or with comments).* *In an email dated November 29, 2006, and an additional telephone conversation dated January 11, 2007, Albert Faure (Department) indicated to Sally Ryan (Department) that, based on his experience, well designed equipment will not "largely" affect the total station (parasitic) power for SCR with diesels. For instance the engines and related cooling systems will radiate heat into the environment. As such, there should be no (or minimal in the case of lay up of the power plant) extra heating cost for the power house building. However, the urea storage building at DHPP will be located separately from the powerhouse, justifying some additional heating costs. Absent detailed information, the Department cannot verify the estimates. The Department notes that the City's design could incorporate heat recovery from the engines, the engines high temperature cooling water contains significant amounts of heat that can be recovered to support heating needs.* *Regarding energy needed for urea dissolving process, the additional information provided in the comments is helpful. However, the Department independently contacted a vendor (Nick Detour from Miratech on 9/25/06) who indicated that the water temp for mixing urea should be 120°, and the mixture should be maintained at between 40 and 50°. The City has not provided any additional evidence for requiring 100°F.[6] Further, based on personal experience, Albert Faure has indicated to the Department that the energy needed to provide the temperature increase to accommodate the urea-dissolving process is fairly low. Well designed and insulated storage tanks and transportation piping of the urea sol'n will keep heat losses and power req'ts to a minimum.*

24	(2) Annual catalyst replacement seems high considering NJUS....	The catalyst costs are based on quotations from the manufacturer. The NJUS plant utilized a different plant arrangement in analyzing SCR catalyst replacement that would result in considerably less labor than the Unalaska plant. The NJUS arrangement is not possible in Unalaska due to site constraints. The Miratech quotation is not comparable as it does not include freight or delivery and has not been approved by Wartsila.	*As shown in Attachment A, the City estimated annual catalyst replacement cost of $67,200 ($60,000 material cost per layer and $7,200 labor - assuming 60 hours of labor at $120 per hour). . Based on the comment, this cost includes shipping. The application contained a copy of the Wärtsilä estimate for an SCR/SCO units **capital cost** in the 8/9/06 packet, but no itemized cost per layer of catalyst replaced, labor, or freight and delivery.* *Regarding material costs only, the cost spreadsheet for Nome indicates catalyst replacement was $24,000 per unit per year (not including labor). Department also has a recent estimate from Miratech dated July 24, 2006 indicating per unit catalyst replacement cost of $49,286 over ten years for a Wärtsilä 12V32C engine - less than $10,000 per year for two units (not including labor). The Department prepared a ball-park estimate for freight of 3,500 per year.* *Regarding labor, the Department notes that this is a new installation and the building can be designed to optimize safe and efficient SCR component access, even with limited size constraints. The Department has on file records of Wärtsilä's M/V Birka project that describes SCR maintenance in confined spaces.*
25	(3) Item 27c indicates normal maintenance....	There is no comparison to the methodology and procedures used for the NJUS units without adjusting for inflation and different operating conditions. As explained to the Department in the August meeting, the City does not have the land space to store large quantities of urea; the urea must be delivered in 2,000 lb sacks in container vans, moved from the shipping vans to the mixing building, and the empty vans removed. .	*As shown in Attachment A, the City estimated annual normal maintenance cost of about $312,000 per year, based on two person years at a labor rate of $75 per hour. (Department assumed 2,080 hour per person year – 40 hours per week times 52 weeks per year). The labor rate seems reasonable, but even with the additional detail proved in the comments it is difficult to imagine two people full time as indicated in the cost estimate.* *For DHPP, the Department has allowed one person full time, which should account for special DHPP circumstances. This is a new installation and the Department assumes that proper planning will maximize use of equipment and personnel.*

[6] The City has indicated that they have backup information on all cost estimates, which they did not submit with the application. For the preliminary permit, with the objective to save time, the Department elected to do a "sensitivity analysis" to see if reducing the most critical O&M costs provided by the City would change the outcome. As it did not, the Department did not make additional requests for information. The City did not provide the backup cost with the comments either.

25	(1) The capital costs for the urea building and powerhouse expansion are assigned to Phase 2	Remove this comment. Apply all associated Phase 2 SCR building costs to Phase 1 As noted previously, the Department cannot mandate that the City build the building to accommodate SCR's for Phase 2 engines.	*The Department disagrees. The City requested authorization to install engines with greater than or equal to 30 liters per cylinder displacement. This will require a NO_X emission control technology equivalent to SCR. Therefore, all costs for the emission control technology should be assigned to phase 2.*
25	(2)	The reduction of incremental station service load and maintenance costs is unwarranted and not justified by the Department, please provide detailed explanations for the reductions that do not reference other projects that are not relevant to the Unalaska powerhouse and include all shipping, and escalation factors. Please provide calculations for stations service loads that are required to heat the urea storage building, mixing solution and additional air handlers and the Department's assumptions for each.	*Each permit applicant must provide concise and verifiable calculations. The Department did not have adequate information to verify the cost estimates provided by the City. The Department reached the same conclusion as the City regarding final BACT for phase 1 engines regardless of the effect of these costs.*
24	Table 12, Table Note b	Remove note "b" -The City has offered and can provide supplemental O&M costs	*The City has not provided this detail as of yet. The Department was able to reach the same conclusion as the City with the information provided. Footnote removed because it is unnecessary.*
26	Phase 2 (Units 15 and 16) NOx BACT Assessment	Remove comment starting "(As previously mentioned....)" This is redundant..	*TAR revised as requested.*
26-28	CO BACT Analysis	Remove CO BACT analysis and associated conditions from permit. Wärtsilä provided updated emission data and power plant project no longer meets the 100 ton/year PSD or minor permit applicability criteria. Delete entire sections discussing SCO.	*TAR revised as requested, in accordance with December 7, 2006 request to avoid PSD for CO.*
30	Phase 2, "(2) Remove Units 1 through 9 upon acceptance of Units 15 or 16"...)"	Reword: u"e "star"up" in place "f "accepta"ce". One of the Phase 2 emission units needs to be in place and functional prior to decommissioning the existing units.	*Assume comment means "use 'startup' in place of 'acceptance'". TAR revised.*

	4.8 New Source Performance Standards… The City did not specify the cylinder size…..	As previously documented, the City has not determined the engines to be installed in Phase 2 of the permit. The selection of engines will be determined at the time units are warranted.	*The permit authorizes engines with cylinder displacement of greater than 30 liters per cylinder. If the City wishes to install something other than this, then they will need to get a permit amendment because there was not an adequate BACT analysis done for the smaller sized engines.*

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Attachment A

Page A-2 of RIA, with Back-Calculated Costs (1 page)

from 9/22/06 Rate Impact Analysis

Phase 1 O+M as calc. by City

SCR

	consum-able $	labor $
23. Capital costs of SCR's for two Wärtsilä units are assumed to be $5.46 million. The incremental capital costs for SCR's for two additional Wärtsilä units are assumed to be $2,476,000, or $1,238,000 per unit.		
24. Capital costs are assumed to be debt funded with amortization at 7.25 percent over 20 years, level debt.		
25. Depreciation of the capital costs is recovered over 20 years.		
26. Incremental station service due to heating, pumping, and other loads is assumed to average 547,260 kilowatt-hours per year.	80872	
27. Incremental operating costs, exclusive of urea, are assumed as follows. Where costs differ between two and four units, the difference is noted.		
a. Water – 1,000 gallons/day per unit at a rate of $0.0019/gallon. Testing is assumed to be $91.80 per year. 1000 gal/day x 2 units x 365 day/yr x 0.0019/gal	1,387	92
b. Catalyst Replacement – Each year from the second year of operation and thereafter, a single layer per unit is assumed to be replaced. Replacement costs are assumed to be $60,000 per layer plus an incremental labor amount of 60 hours/layer at a rate of $120/hour. 60,000/yr x 1 layer/yr = 60,000; 60 hr/layer x 1 layer/yr x $120/hr = 7,200	60,000	7,200
c. Normal Maintenance – Incremental labor costs due to the SCR's is two person-years (three for four units) at a labor rate of $75/hour. 2 person yrs x 2080 hr/person yr x 75/hr		312,000
d. Filters – Two filters per unit per year at a cost of $1,000 per filter. Incremental labor is assumed to be 1 hour/filter replacement at a labor rate of $75/hour. 2x1000; 1 hr/filter x 2 filters/unit x 2 x 75/hr	2000	300
e. Water Softener Salt - $250/year per unit. $250 x 2	500	
f. Hazardous Waste Disposal - $3,150/year per unit. 3150 x 2	6,300	
28. Urea consumption is assumed to be 105 lbs/operating hour per unit. Usage is assumed to not vary significantly over the unit loadings that will be incurred by each unit. 105 lb/hr x 8760 hr/yr x 2 x ton/2000 lb x $300/ton	276,000	
29. Urea costs are assumed to be $300/ton for materials and $0.30/lb for shipping. Shipping costs are closely tied to the price of fuel and can vary significantly on a monthly basis. 919.8 tons x 2000 x 0.30/ton	551,880	

cons 977939
labor 319592
total → $1,297,531

from Table 2 547,260 kw-hr/yr = 30403 gal fuel/yr
30403 gal/yr x $2.66/gal = $80,872

compare to table 5 O+M costs 9/22/06 (they are 1,200551 avg 2009-201?)

Attachment B

Table 2 of RIA with Dollar Amounts

From 9/22/06 RFA

station service loads are typically reflected in the overall generating efficiency in kilowatt-hours of <u>sales</u> per gallon of fuel. Table 2 shows that the additional fuel consumption due to the SCR's is approximately 30,400 gallons per year.

Table 2
CITY OF UNALASKA SCR ANALYSIS
Additional Fuel Consumption Due to SCR for phase 1

Item	Load/Hr (kW)	Hours/ Day	Days/Yr	Annual Energy (kWh)	
Building Heat	18.8	24	250	112,800	x1/18 x 2.66 = 16,669
Building Lights	1.0	24	365	8,760	1295
Process Heater 1	30.0	24	182.5	131,400	19418
Process Heater 2	60.0	24	182.5	262,800	38836
Softner, RO skid, Booster Skid, Mixing Equip.	5.0	24	182.5	21,900	3236
Heat Trace System (Assume 100 ft.)	1.6	24	250	9,600	1419
Total				547,260	80873
Assumed Generating Efficiency (kWh/gallon)				18.0	
Additional Fuel Requirement (gallons/year)				30,403.3	